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Population and Characteristics of Industrial/Commercial Boilers in the U.S.

PEDCo-Environmental, Inc, Cincinnati, OH

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, NC

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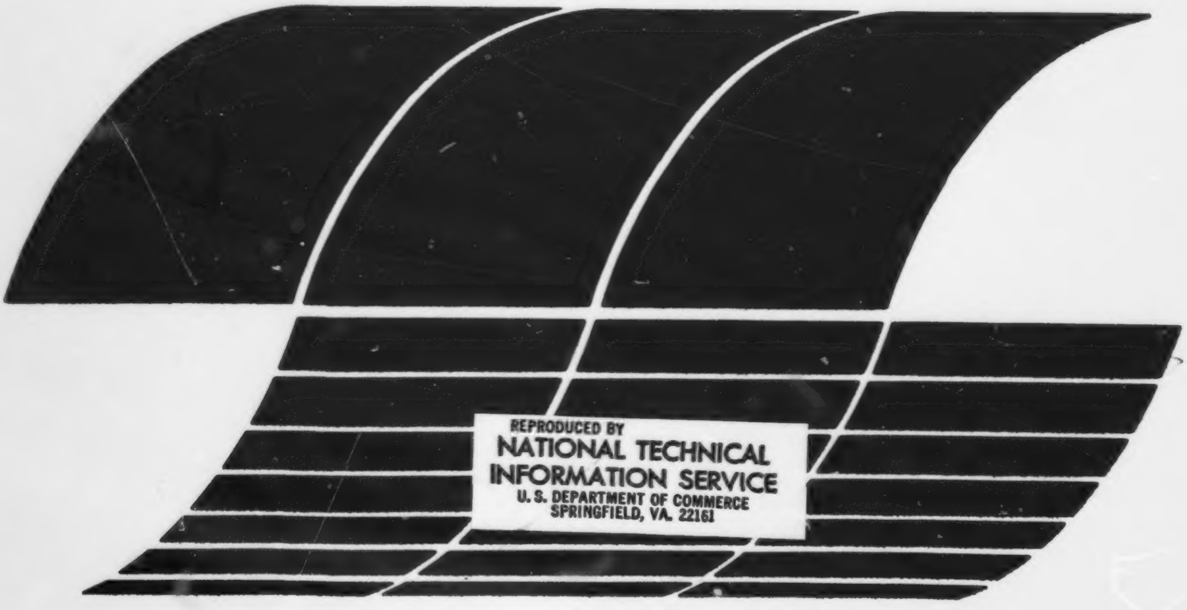
Interagency Energy/Environment R&D Program Report



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16. ABSTRACT The report describes a study of boiler population and characteristics, fuel consumption, emissions, and boiler costs that provides a basis from which a broader study of overall environmental impacts of non-utility boilers can be made. Boilers consume about one-third of the fossil fuels burned in the U.S. Over 40% of this is fired in industrial/commercial boilers; the rest, in utility boilers. There are about 1.8 million industrial/commercial boilers in the U.S. Only about 0.1% of these have a firing capacity greater than 73.2 MW. These larger boilers, however, represent 17% of the total U.S. capacity. About 72% of the total boilers are classified as commercial, used primarily for space heating. The industrial boilers represent 69% of the total firing capacity and are concentrated in four major industries: pulp and paper, primary metals, chemicals, and minerals. Estimated uncontrolled particulate matter emissions in 1975 from industrial/commercial boilers were about 2.5 Tg per year in addition to about 2.9 Tg per year of SOx and 1.8 Tg per year of NOx. CO and HC emissions are relatively minor. Using a 3.3% annual growth rate, the emissions will more than double by the year 2000. Capital and annualized operating costs were determined for 23 boiler/fuel combinations representing a cross section of the boiler population.

17. KEY WORDS AND DOCUMENT ANALYSIS

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Boilers		Stationary Sources	13A	
Population (Statistics)			12A	
Characteristics			14B	
Fuel Consumtpion			21D	
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by

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Office of Energy, Minerals, and Industry
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Prepared for

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Washington, DC 20460

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PREFACE

The 1977 Amendments to the Clean Air Act required that emission standards be developed for fossil-fuel-fired steam generators. Revisions to the 1971 new source performance standard (NSPS) for large steam generators were recently promulgated by the U.S. Environmental Protection Agency (EPA). Further, EPA has undertaken a study of industrial boilers with the intent of proposing an NSPS for this category of sources. The study is being directed by EPA's Office of Air Quality Planning and Standards, and technical support is being provided by EPA's Office of Research and Development. As part of this support, the Industrial Environmental Research Laboratory at Research Triangle Park, N.C. prepared a series of technology assessment reports to aid in determining the technological basis for the NSPS for industrial boilers. This report is part of that series. The complete report series is listed below:

Title	Report No.
The Population and Characteristics of Industrial/Commercial Boilers	EPA-600/7-79-178a
Technology Assessment Report for Industrial Boiler Applications: Oil Cleaning	EPA-600/7-79-178b
Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal	EPA-600/7-79-178c
Technology Assessment Report for Industrial Boiler Applications: Synthetic Fuels	EPA-600/7-79-178d
Technology Assessment Report for Industrial Boiler Applications: Fluidized-Bed Combustion	EPA-600/7-79-178e
Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modification	EPA-600/7-79-178f
Technology Assessment Report for Industrial Boiler Applications: NO_x Flue Gas Treatment	EPA-600/7-79-178g

Technology Assessment Report for Industrial Boiler Applications: Particulate Collection	EPA-600/7-79-178h
Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization	EPA-600/7-79-178i

These reports will be integrated along with other information in the document, "Industrial Boilers - Background Information for Proposed Standards," which will be issued by the Office of Air Quality Planning and Standards.

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The project was conducted under the overall direction of Mr. Timothy W. Devitt. The PEDCo Project Director was Mr. William F. Kemner. Mr. Larry L. Gibbs was Project Manager. Principal authors were Messrs. Devitt, Spaite, Gibbs, Kemner, Duane S. Forste, Douglas A. Paul, and John P. Abraham.

EXECUTIVE SUMMARY

PURPOSE

This report represents an initial background study to generate data in support of technology assessment studies for industrial and commercial boilers. Industrial boilers are defined as boilers used to generate process steam, electricity, or space heat at industrial facilities. Commercial boilers are defined as those used by commercial establishments, medical, or educational institutions to provide steam. The project was designed primarily to provide information to meet the specific needs of other contractors responsible for conducting control technology assessment studies. In addition, this study provides the statistical basis for boiler population and characteristics, fuel consumption, and emissions from which a broader study of overall environmental impacts of nonutility boilers can be made.

Boilers consume about one-third of the fossil fuels burned in the United States. Over 40 percent of these fuels are fired in industrial/commercial boilers, the rest in utility boilers. Although many studies have been made of utility boilers to ascertain their energy consumption and the nature of their emissions, no prior study has attempted to make a comprehensive assessment of the total impact of criteria pollutant emissions from industrial/commercial boilers. An earlier Battelle report (Locklin et al., 1974) was limited to the study of nitrogen oxides emissions and the various technologies for controlling them. Other reports (Ehrenfeld et al., 1971; Putnam et al., 1975) stopped short of completely describing the amounts and kinds of air pollution associated with all important categories of boilers. This study updates and enlarges the work of others to provide the most complete description yet developed of the industrial/commercial boiler population, its fuel consumption, and associated atmospheric emissions.

It should be noted that this study makes exclusive use of the International System of Units (SI). Boiler capacities are expressed in watts thermal, the SI unit for power. Because the data from which the statistics on boilers were obtained are in English units, values are converted to the SI system.

There were about 1,800,000 industrial and commercial boilers in the United States in 1977. Only about 0.1 percent of these boilers, representing 17 percent of the total capacity, have a heat input greater than 73.2 MW thermal (250×10^6 Btu/h), the current size limit for boilers covered by New Source Performance Standards (NSPS). The current NSPS for boilers therefore generally do not apply to this nonutility segment of the population. It should be noted that this study does not concern itself with residential boilers.

Nearly every State Implementation Plan (SIP) contains regulations applicable to boilers of all sizes. Regulations covering particulate matter and sulfur oxides (SO_x) are usually specific, although those for SO_x often take the form of fuel regulations and are independent of boiler size.

Emission limitations for nitrogen oxides (NO_x), carbon monoxide (CO), and hydrocarbons (HC) are essentially nonexistent in the SIP's. Furthermore, surveys of Regional Offices, presented in an interim report, indicate that regulations covering smaller boilers have not been rigorously enforced.

Recognizing that these industrial and commercial boilers represent a significant stationary source of emissions, Industrial Environmental Research Laboratory/Research Triangle Park formulated this study with two major objectives:

- To develop a thorough and complete characterization of the existing boiler population by developing subcategories of boiler types, boiler sizes, fuel usage, and uncontrolled emissions.

- To develop a standardized approach and basis for determining the cost of new boilers and their associated emission control systems.

ORGANIZATION OF THE REPORT

The report is organized into six sections and seven appendices. Section 1 describes the scope of the study and the key subtasks. Section 2 characterizes the existing boiler population and presents the statistical data base. It includes important descriptive and analytical subcategories regarding the boiler population. This section also presents projections of growth of boilers under various scenarios. Section 3 presents estimates of uncontrolled emissions from existing boilers and projected emissions through the year 2000. It includes a separate subsection for each of the pollutants: particulate matter, SO_x, and NO_x.

Section 4 provides the basis for the selection of standard boilers representing a cross section of the industrial/commercial population. It describes 23 boiler and fuel type combinations and specifies the key design parameters and boiler characteristics for each case.

Section 5 establishes a uniform procedure to be used in calculating capital and annualized costs for new boilers and emission control systems. It also provides formats for presentation of capital and annualized costs and recommended values for unit costs.

Section 6 concludes the main body of the report and describes the methodology for determining the capital and annualized costs of several standard boilers. It also defines the sources of data and key assumptions used to develop boiler costs.

Because this effort is a cornerstone study to be used by diverse groups, considerable detail is provided in appendices. These appendices can be used to follow the derivation of the data, and they also provide the necessary detail for those performing additional work. Key study assumptions are identified.

For those interested only in the overview, however, no important factors will be missed if the appendices are not addressed.

RESULTS

Time constraints made it necessary to perform a number of tasks concurrently. These constraints also necessitated making first estimates on the basis of readily available information and then upgrading the data base as additional background information became available. Boiler surveys and sales data provided the basis for characterizing the boiler population. Fuel supply, demand, and consumption data from various sources were used to estimate fuel consumption. Preliminary calculations of emission estimates were based on boiler capacity data and estimated use factors, and later calculations were based on fuel consumption data and accepted emission factors. The two approaches produced different results. The estimates made from fuel consumption data (the second approach) were considered more reasonable and were used in the final report. The differences between the results of the two approaches are discussed, but the limits of the study precluded reconciling all the data, which were generally gathered and reported in different ways. It is believed that, despite problems encountered in interpreting the data, the work to date provides a valuable new perspective to the nature of the air pollution problems generated by the industrial and commercial boilers of the United States.

The total number of industrial and commercial boilers in place in 1977 is estimated to be about 1,800,000. The total firing capacity of these boilers is about 1,300,000 MW thermal (4,500,000 x 10^6 Btu/h). Less than 1 percent of the boilers exceed the existing NSPS limiting size of 73.3 MW thermal (250 x 10^6 Btu/h), but they represent 17 percent of the installed capacity. About 72 percent of these boilers are classified as commercial and are used primarily for space heating in commercial and institutional buildings. The other 28 percent are classified as industrial boilers and are used primarily for generating process steam and for space heating. Although the absolute number of commercial boilers is obviously greater, the industrial boilers are generally much larger. Consequently, industrial boilers represent 69 percent of the total firing capacity. The use of industrial boilers is concentrated in four major industries: pulp and paper, primary metals, chemicals, and minerals. These industries account for 82 percent of the total energy used to make process steam.

Figure 1 summarizes the capacity and types of boilers in the industrial and commercial categories.

The three major types of boilers are water-tube, fire-tube, and cast iron. Many variations in boiler design are possible, but these three categories represent an important basic classification. Figure 2 illustrates the distribution of the boiler population by size within these three categories. In contrast, Figure 3 illustrates the distribution on the basis of firing capacity. It is apparent that cast iron boilers are small, the largest having a heat input of 2.9 MW thermal (10 x 10^6 Btu/h). Fire-tube boilers have the greatest range of capacity, and water-tube boilers are generally the largest of the three types. Thus, although there are relatively few water-tube boilers, they constitute the majority of the capacity. Further analysis indicates that water-tube boilers predominate in industry. About three-quarters of water-tube boilers are package units (i.e., fabricated in the shop and shipped to the user as a complete unit). Field-erected units supply more than half the total capacity of water-tube boilers because they tend to be larger than package units.

Figure 4 illustrates the distribution of relative firing capacity by fuel type for each type of boiler. Natural-gas-fired boilers comprise 45 percent of the total of commercial and industrial boilers. Oil-fired boilers comprise 37 percent, and coal-fired boilers the remaining 18 percent. The uncontrolled particulate emissions from coal-fired boilers are dispropor-

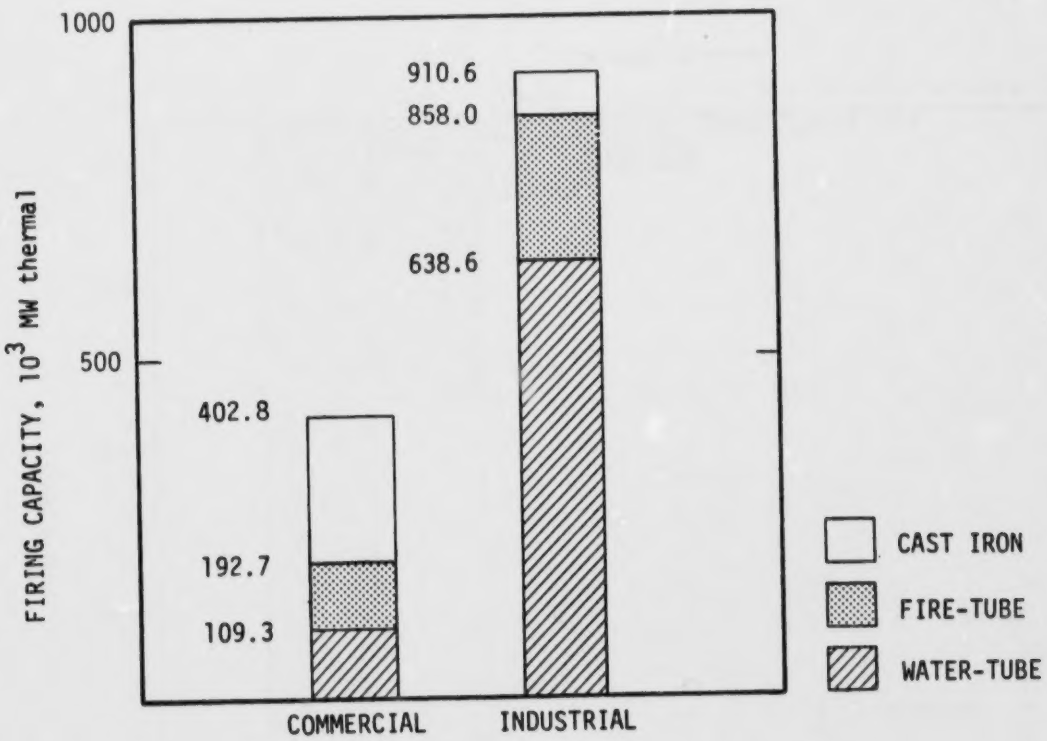

Figure 1. Distribution of commercial and industrial boiler capacity by type.

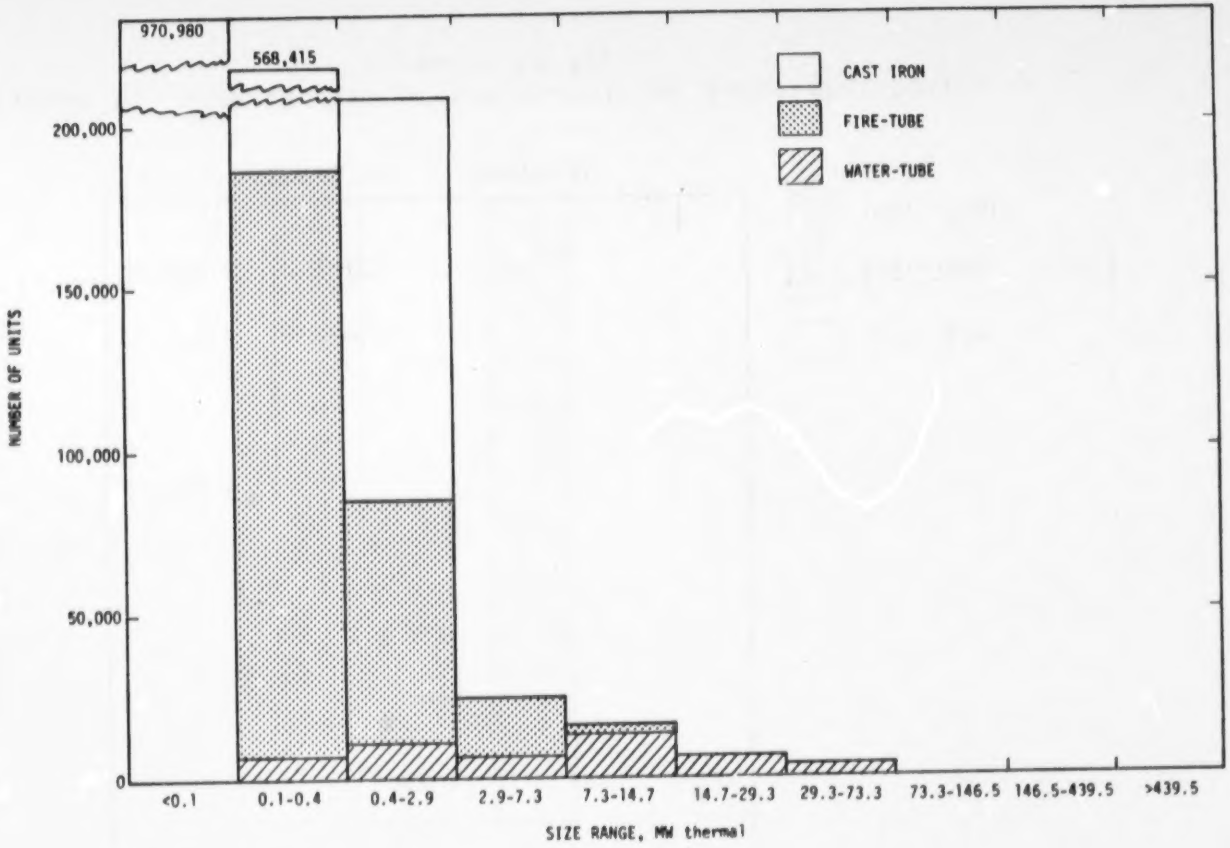

Figure 2. Relative distribution of the number of industrial/commercial boilers by type and size range.

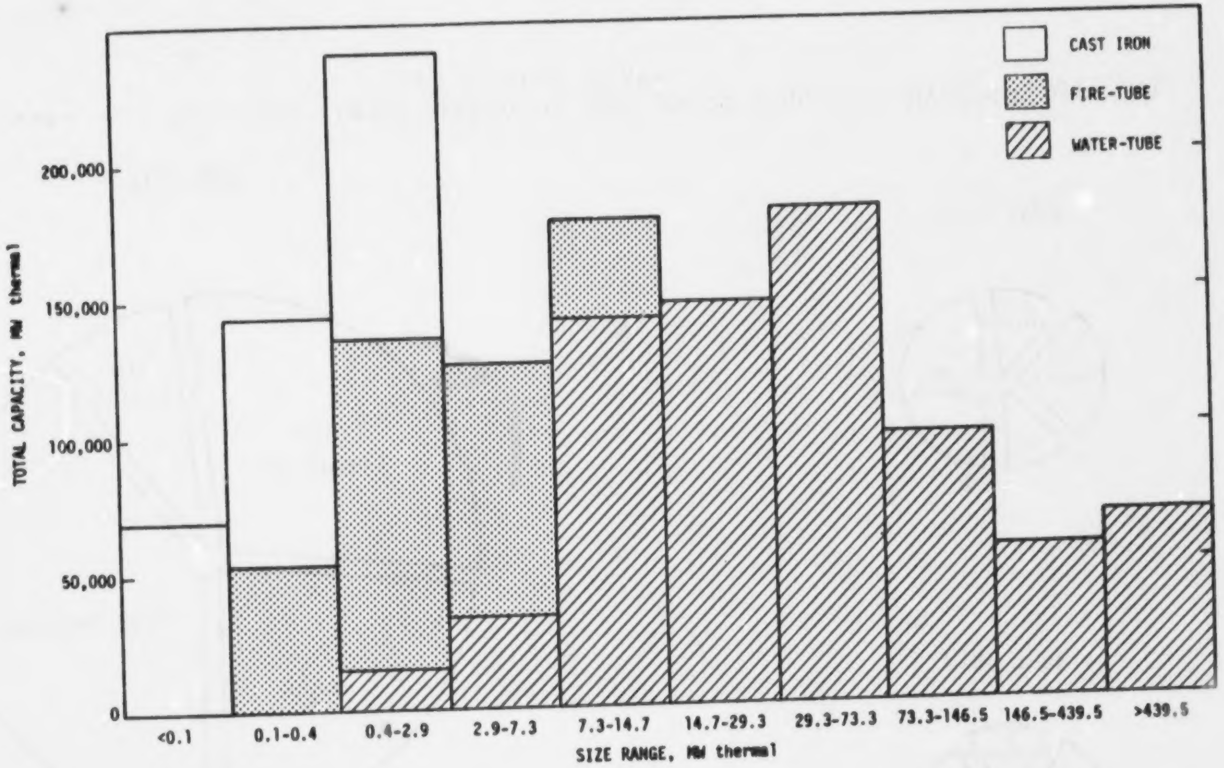

Figure 3 Relative distribution of the capacity of the industrial/commercial boiler population by type and size.

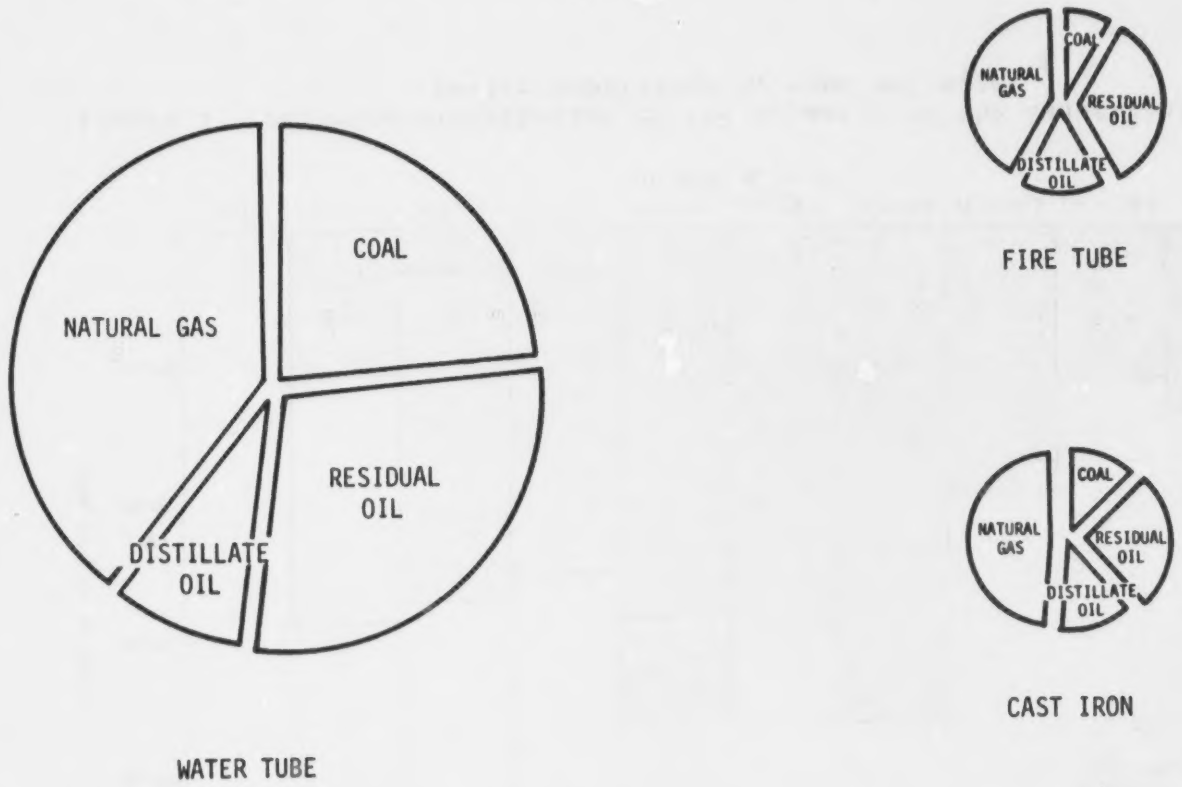

Figure 4. Relative distribution of the total capacity by fuel type in each boiler class.

tionate to the total amount of coal used relative to other fuels because of the ash contained in coal.

Calculations of uncontrolled emissions from all boilers were based on estimates of 1975 fuel consumption. Calculations of projected emissions through the year 2000 were based on a 3.3 percent yearly growth rate in the consumption of fuel by boilers. Figure 5 illustrates the resultant emission quantities for three pollutants considered. This figure also shows the emissions by boiler type. As shown in Figure 5, uncontrolled emissions will more than double by the year 2000.

Two other annual growth rates under various scenarios were analyzed, 0.5 and 4.6 percent. Uncontrolled emission rates under these scenarios are also presented in the report. The projections do not take into account the expected increase in emissions resulting from coal conversion strategies and increased use of coal; insufficient data are available to quantify the extent of such conversion. Particulate matter and SO_x are obviously the major pollutants emitted by boilers, nitrogen oxides are next in significance, and CO and HC are relatively minor.

Based on the fuel consumption estimates and the total installed firing capacity, load factors were estimated for the various boiler categories. These load factors are significantly lower than previously published estimates, the overall average load factor being 26 percent rather than the 35 percent published by Battelle (Putnam et al., 1975). The load factors calculated in this report may be unrealistically low because of the methods used to calculate replacement boiler capacity versus new capacity. It is doubtful, however, that the actual load factors are as high as previous estimates, indicating that a large number of boilers are on standby and used seasonally.

In order to assess the relative impacts of various control strategies on the costs of new industrial boilers, PEDCo selected 23 boiler/fuel combinations for detailed cost estimating. Table 1 presents the boiler/fuel combinations selected. Key operating and design parameters were specified for each of the

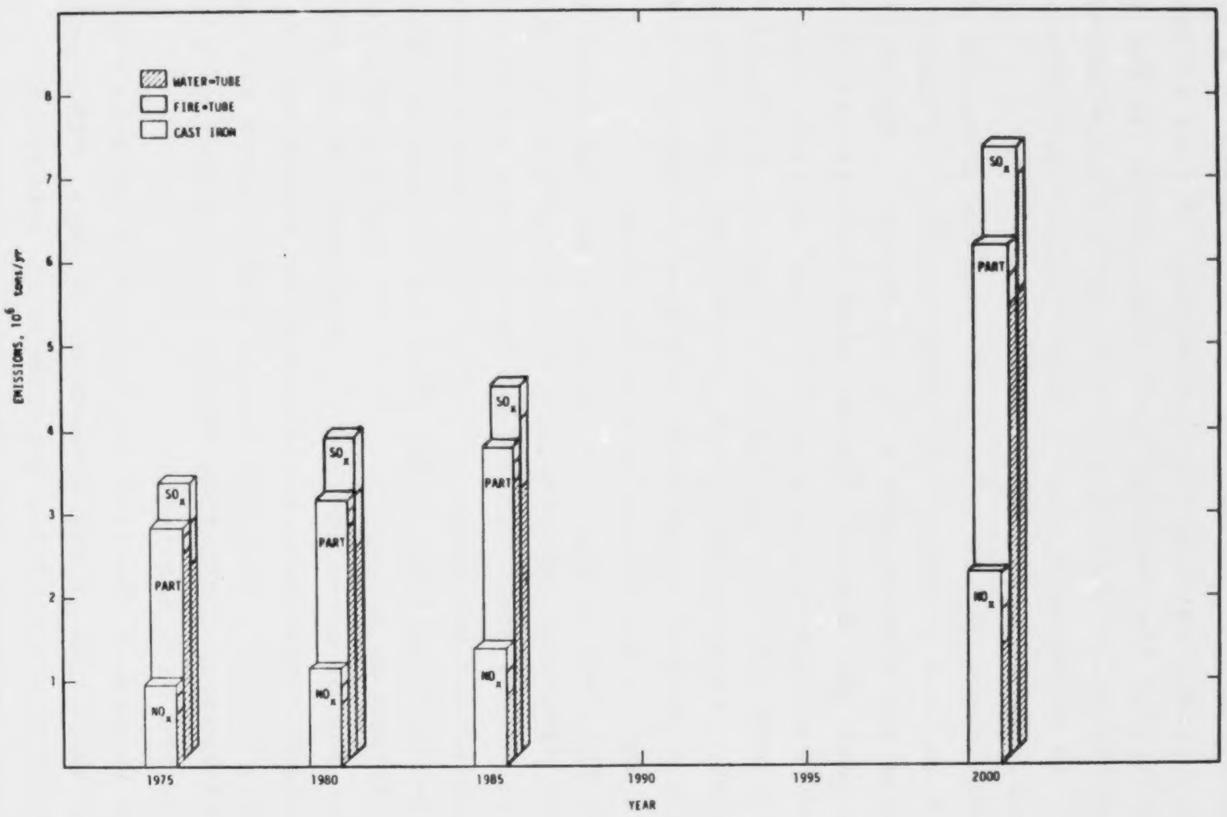

Figure 5. Relative total emission levels of particulate matter, SO_x, and NO_x by boiler class for the period 1975 through 2000.

boiler fuel combinations including boiler configuration, design heat input rate, fuel analysis, fuel consumption, air pollutant emission rates, excess air usage, flue gas characteristics, and annual load factor. These parameters are necessary for the design of the various control technologies applicable to boilers.

In addition, standardized formats and bases are used for estimation of costs of boilers and of various control methods. Guidelines were developed for the items to be included under direct capital costs, indirect capital costs, working capital, annual operation and maintenance costs, overhead, and fixed annual costs. For consistency, the costs of boilers and control equipment are based on a new installation in the Midwest.

The costs for representative new boilers and fuel type combinations have been calculated according to the uniform procedure. These costs are summarized in Table 2 for each of the 23 boiler/fuel combinations. The total installed capital costs range from $389,800 for a package fire-tube boiler firing natural gas with a heat input of 4.4 MW thermal (15×10^6 Btu/h) to $26,836,600 for a field-erected water-tube boiler firing pulverized subbituminous coal with a heat input of 117.2 MW thermal (400×10^6 Btu/h). These costs include land and working capital and represent June 1978 dollars. The cost of boilers is highly dependent on firing capacity and fuel.

Total annualized costs for the boilers just cited range from $496,000 to $7,930,000. Although the procedures to be used in determining costs for pollution control equipment are specified, no actual costs have been calculated. Control equipment specifications, control capabilities, and control equipment costs are subjects for future work.

TABLE 1. REPRESENTATIVE BOILERS AND FUELS FOR EVALUATION

Boiler type	Fuel	Heat input, MW thermal (10^6 Btu/h)
Package, Scotch fire-tube	Natural gas	4.4 (15)
Package, Scotch fire-tube	Distillate oil	4.4 (15)
Package, water-tube	Residual oil	8.8 (30)
Package, water-tube, underfeed-stoker	Coal (3 types)	8.8 (30)
Field-erected, water-tube, chain-grate-stoker	Coal (4 types)	22.0 (75)
Package, water-tube	Natural gas	44.0 (150)
Package, water-tube	Residual oil	44.0 (150)
Package, water-tube	Distillate oil	44.0 (150)
Field-erected, water-tube, spreader-stoker	Coal (3 types)	44.0 (150)
Field-erected, water-tube	Pulverized coal (3 types)	58.6 (200)
Field-erected, water-tube	Pulverized coal (4 types)	117.2 (400)

TABLE 2. SUMMARY OF THE ESTIMATED CAPITAL AND ANNUALIZED COSTS FOR THE SELECTED REPRESENTATIVE BOILERS

Boiler type	Fuel	Boiler capacity, MW thermal (10^6 Btu/h)	Capital cost, $	Annual O and M, $	Fixed cost, $	Total annualized cost, $
Package, fire-tube	Natural gas	4.4 (15)	389,800	439,900	56,100	496,000
Package, fire-tube	Distillate oil	4.4 (15)	405,100	501,000	57,600	558,600
Package, water-tube	Residual oil	8.8 (30)	797,800	678,800	109,600	788,400
Package, water-tube underfeed-stoker	Eastern low-sulfur coal	8.8 (30)	1,665,200	721,600	236,300	957,900
Package, water-tube underfeed-stoker	Eastern high-sulfur coal	8.8 (30)	1,891,300	682,500	269,800	952,300
Package, water-tube underfeed-stoker	Subbituminous coal	8.8 (30)	2,257,100	653,300	323,600	976,900
Field-erected, water-tube, chain-grate-stoker	Eastern low-sulfur coal	22.0 (75)	4,067,900	1,330,500	563,400	1,893,900
Field-erected, water-tube, chain-grate-stoker	Eastern medium-sulfur coal	22.0 (75)	4,165,300	1,283,900	577,600	1,861,500
Field-erected, water-tube, chain-grate-stoker	Eastern high-sulfur coal	22.0 (75)	4,554,400	1,217,900	633,300	1,851,200
Field-erected, water-tube, chain-grate-stoker	Subbituminous coal	22.0 (75)	5,341,000	1,120,100	745,700	1,865,800
Package, water-tube	Natural gas	44.0 (150)	2,118,700	2,035,100	287,800	2,322,900

(continued)

TABLE 2 (continued)

Boiler type	Fuel	Boiler capacity, MW thermal (10^6 Btu/h)	Capital cost, $	Annual O and M, $	Fixed cost, $	Total annualized cost, $
Package, water-tube	Residual oil	44.0 (150)	2,244,900	2,223,100	304,100	2,527,200
Package, water-tube	Distillate oil	44.0 (150)	2,379,700	2,793,900	317,100	3,111,000
Field-erected, water-tube, spreader-stoker	Eastern low-sulfur coal	44.0 (150)	7,804,100	2,101,800	1,084,500	3,186,300
Field-erected, water-tube, spreader-stoker	Eastern high-sulfur coal	44.0 (150)	8,784,200	1,849,100	1,225,900	3,075,000
Field-erected, water-tube, spreader-stoker	Subbituminous coal	44.0 (150)	10,395,800	1,665,400	1,455,800	3,121,100
Field-erected, water-tube, pulverized-coal	Eastern low-sulfur coal	58.6 (200)	10,823,200	2,875,600	1,504,400	4,380,000
Field-erected, water-tube, pulverized-coal	Eastern high-sulfur coal	58.6 (200)	12,202,400	2,544,800	1,702,900	4,247,700
Field-erected, water-tube, pulverized-coal	Subbituminous coal	58.6 (200)	14,468,400	2,343,000	2,025,600	4,368,600
Field-erected, water-tube, pulverized-coal	Eastern low-sulfur coal	117.2 (400)	20,094,000	5,317,000	2,792,500	8,109,500
Field-erected, water-tube, pulverized-coal	Eastern medium-sulfur coal	117.2 (400)	20,707,300	4,957,700	2,883,000	7,840,700
Field-erected, water-tube, pulverized-coal	Eastern high-sulfur coal	117.2 (400)	22,638,000	4,624,100	3,159,500	7,783,600
Field-erected, water-tube, pulverized-coal	Subbituminous coal	117.2 (400)	26,836,600	4,171,800	3,758,200	7,930,000

SECTION 1
INTRODUCTION

Boilers, particularly large utility boilers, have long been recognized as major contributors to atmospheric pollution in the United States.* The emissions from boilers include the criteria pollutants (e.g., particulate matter, sulfur oxides, and nitrogen oxides) as well as various metal oxides and possibly some hazardous substances. The emissions are dependent on the fuel that is used, the size and type of the boiler, and of course the number of boilers.

Almost every state has specific regulations governing the emissions of particulate matter and sulfur dioxide from boilers, but emissions of other pollutants are generally not regulated. The U.S. Environmental Protection Agency (EPA) has promulgated regulations for particulate matter, sulfur dioxide, and nitrogen oxides from new boilers with a heat input of 73.25 MW thermal (250×10^6 Btu/h) or larger. To date emphasis has been on enforcing these regulations as they pertain to large utility boilers because of the higher emission values associated with each individual source and in aggregate.

The impact of industrial and commercial boilers on national air quality has not been well defined. Organization of the fundamental data required, such as the number and sizes of boilers by boiler type, the types of fuel used, and the effect of such variables as boiler design on emission rates, has been lacking. Furthermore, basic information on emission rates for noncriteria pollutants, geographical distribution of boilers by type, health effects of specific pollutants, and population-at-risk determinations is limited; however, in the aggregate, it has been recognized that industrial and commercial boilers do contribute significantly to nationwide totals of TSP, SO_x, and NO_x emissions.

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* Throughout this report the term "boiler" is used to represent a steam generator system consisting of both a furnace where the fuel is burned and a boiler in which the water is heated for use as hot water or steam.

The purpose of this study is to develop the data base to conduct a comprehensive evaluation of the environmental impacts of industrial and commercial boilers.

Specifically, the tasks defined by the Industrial Environmental Research Laboratory, Research Triangle Park (IERL-RTP) for study were:

- Categorize the boilers in the United States by type, number, capacity, fuel consumption and use; project the growth within these categories.
- Estimate air pollutant emissions from industrial and commercial boilers as a function of boiler type and fuel use.
- Establish the technical and cost bases for evaluating the cost of boilers and emission control systems.
- Select representative boilers for detailed cost evaluation and for control technology assessment studies.
- Estimate capital and annualized costs for the representative boilers.

The information obtained in the performance of these tasks will form the basis for control technology assessment studies for the generation of Individual Technology Assessment Reports (ITAR).

The initial step in the project was to characterize the U.S. boiler population by establishing categories for boilers with similar air emissions for possible development of individual standards. (Utility and residential boilers were outside the scope of the study by definition.) Characterization involved identifying the types of boilers in use and then estimating the number of boilers in each category and their total fuel-burning capacity. The basic boiler population data were developed by updating and expanding upon prior boiler studies by Walden (Ehrenfeld et al., 1971) and Battelle (Locklin et al., 1974;

Putnam et al., 1975). Material for updating was supplied by the American Boiler Manufacturers Association (ABMA), the Hydronics Institute (HI), the Department of Energy (DOE), and the EPA.

The next step was to determine the amount of fuel consumed in each boiler category of the present boiler population. Consumption of the various fuels by boiler type was based on available data from annual surveys by government agencies such as the Bureau of Mines and the Department of Energy.

Estimates of growth in boiler use and fuel consumption through 2000 were based on forecasts and estimates from previous studies by others (Stanford Research, 1972; Fejer and Larson 1974; Edison Electric Institute, 1976; Energy Information Administration, 1977).

Total aggregated emissions from the existing and projected industrial boiler population were then estimated, based on fuel consumption data and published emission factors in Compilation of Air Pollutant Emission Factors, AP-42 (EPA, 1977).

Given this foundation, the next step was to provide a basis for conducting cost evaluations. These technical and cost bases were developed for use by other contractors in their assessment of costs of emission control systems. Standardized procedures, formats, and prices were determined with guidance from the Economic Analysis Branch (EAB) of the EPA. Recommended values for specific cost items were obtained by surveying trade publications and contacting marketing organizations.

Specific boilers were selected for detailed cost estimation. Selection of representative units was based on three criteria: the portion of the boiler population each unit represents, the potential emissions contribution of the unit, and a representation of each of the various fuel types. Design and operational parameters for each boiler were determined from published manufacturers' data and engineering calculations.

The cost guidelines developed in the study were used to estimate costs for each of the representative boilers, based on quotes from equipment manufacturers.

Section 2 describes the development of the boiler population and fuel consumption data base. Section 3 discusses atmospheric emission estimates and projections. Section 4 describes the design characteristics of the boilers considered representative of important boiler categories. Section 5 presents the basis to be used in developing boiler and control equipment costs (including the elements that should be included in cost evaluations), the recommended format for presentation of results, and unit price recommendations for annual operating cost elements. Section 6, which presents representative boiler costs, concludes the body of the report. The appendices describe the methodology used and present details of the boiler population data base.

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SECTION 2

THE INDUSTRIAL/COMMERCIAL BOILER POPULATION AND FUEL CONSUMPTION

The population of industrial/commercial boilers consists of many different types of units, which use various fuels and methods of heat transfer. The following subsections present the categories of classification for industrial/commercial boilers, the population of each category, the fuels consumed in each category, and the projections of growth of fuel consumption by the boiler population through the year 2000.

2.1 BOILER CLASSIFICATION

Boilers can be and have been classified in a number of ways, using such bases of categorization as boiler type, fuel use, and method of manufacture. Two main factors were considered in selecting the parameters of classification for this study. First, consideration was given to whether variation in the parameter was likely to produce a significant change in air emissions. The second consideration asks whether the parameter had been regarded as an important variable in collecting and storing the data needed to construct boiler population estimates. The final list of parameters was developed from analysis of past work and reflects comments of reviewers who are associated with boiler manufacturing organizations and know what data are available.

The basic boiler classifications appear in Table 2-1. As the table shows, units were categorized by construction method and heat transfer configuration, then by firing mechanism and fuel. Descriptions of the various types of boilers shown in Table 2-1 are presented in Appendix A.

Each type of industrial/commercial boiler was further subcategorized by heat transfer mechanism, type of use, and size, using the following classification scheme.

TABLE 2-1. CATEGORIES OF INDUSTRIAL/COMMERCIAL BOILERS

- Field-erected/Water-tube
  - Pulverized coal
  - Spreader-stoker
  - Overfeed-stoker coal
  - Underfeed-stoker coal
  - Residual oil
  - Distillate oil
  - Natural gas
- Package Boilers/Water-tube
  - Pulverized coal
  - Spreader-stoker coal
  - Overfeed-stoker coal
  - Underfeed-stoker coal
  - Residual coal
  - Distillate oil
  - Natural gas
- Package/Fire-tube
  - Coal/Horizontal Return Tubular (HRT)
  - Coal/Firebox
  - Coal/Scotch
  - Coal/Other
  - Residual oil/Horizontal Return Tubular (HRT)
  - Residual oil/Firebox
  - Residual oil/Scotch
  - Residual oil/Other
  - Distillate oil/Horizontal Return Tubular (HRT)
  - Distillate oil/Firebox
  - Distillate oil/Scotch
  - Distillate oil/Other
  - Natural gas/Horizontal Return Tubular (HRT)
  - Natural gas/Firebox
  - Natural gas/Scotch
  - Natural gas/Other
- Package/Cast Iron
  - Coal
  - Residual oil
  - Distillate oil
  - Natural Gas

- Heat transfer medium:
    - Supercritical steam
    - High-pressure steam
    - Low-pressure steam
    - Hot water
- Use:
    - Commercial/institutional space heating
    - Industrial space heating
    - Industrial process heat
- Size:

MW thermal	(Btu/h)
Equal to or under 0.1	(Equal to or under 0.4×10^6)
Over 0.1 - 0.4	(over 0.4×10^6 - 1.5×10^6)
Over 0.4 - 2.9	(over 1.5×10^6 - 10×10^6)
Over 2.9 - 7.3	(over 10×10^6 - 25×10^6)
Over 7.3 - 14.7	(over 25×10^6 - 50×10^6)
Over 14.7 - 29.3	(over 50×10^6 - 100×10^6)
Over 29.3 - 73.3	(over 100×10^6 - 250×10^6)
Over 73.3 - 146.5	(over 250×10^6 - 500×10^6)
Over 146.5 - 439.5	(over 500×10^6 - 1500×10^6)
Over 439.5	(over 1500×10^6)

Possible combinations of the classifications used in this study are illustrated in Figure 2-1.

During the course of the study, many rearrangements of the data were used to compare the relative significance of various categories, with regard to such factors as total capacity, fuel consumption, and emissions. The next section describes the boiler population according to the final classifications selected.

2.2 PRESENT BOILER POPULATION

Estimates of the number and capacity of present industrial/commercial boilers are derived from combining data in studies by Battelle (Locklin et al., 1974; Putnam et al., 1975) and Walden (Ehrenfeld et al., 1971) with sales records of the American Boiler Manufacturers Association (ABMA) and the Hydronics Institute (HI).

The total number of boilers categorized by fuel type, size, type of use, heat transfer configuration, and method of construction

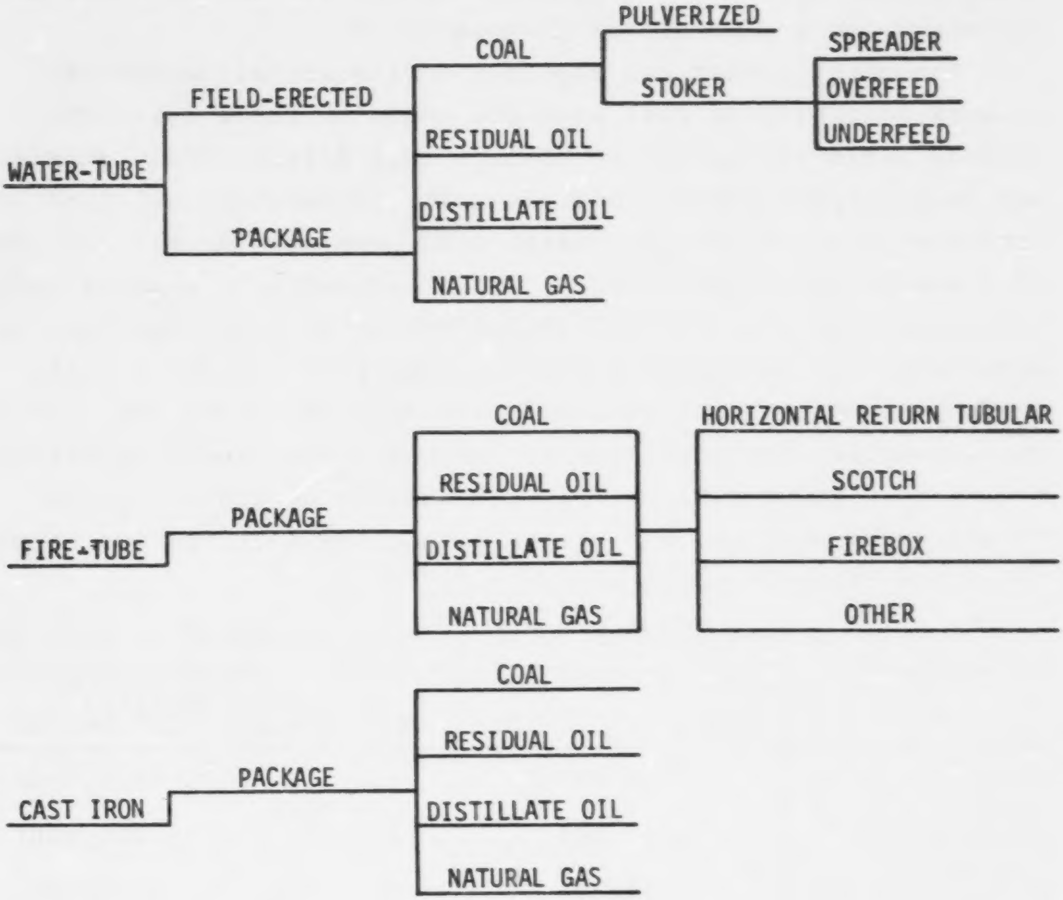
WATER-TUBE
FIELD-ERECTED
PACKAGE
COAL
RESIDUAL OIL
DISTILLATE OIL
NATURAL GAS
PULVERIZED
STOKER
SPREADER
OVERFEED
UNDERFEED
FIRE-TUBE
PACKAGE
COAL
RESIDUAL OIL
DISTILLATE OIL
NATURAL GAS
HORIZONTAL RETURN TUBULAR
SCOTCH
FIREBOX
OTHER
CAST IRON
PACKAGE
COAL
RESIDUAL OIL
DISTILLATE OIL
NATURAL GAS

Figure 2-1. Possible combinations of characteristics associated with U.S. industrial/commercial boilers.

(i.e., package versus field-erected) are discussed in the following subsections. The methods used to develop the estimates are explained in Appendix B. Data sheets for all boiler types and subcategories are presented in Appendix C.

The total number and capacity of industrial/commercial boilers according to fuel used are shown in Table 2-2. The various fuels are burned in boilers that differ widely in size, use (e.g., space heating and electric generation), and type of hardware (e.g., fire-tube, water-tube, and cast iron). In order to focus on these differences, it is necessary to examine various subcategories. The nonutility boilers being considered can be separated into two broad sectors, commercial and industrial. Commercial boilers are generally the smaller of the two, and are used primarily for space heating in commercial and institutional buildings. Industrial boilers are used to generate process steam, space heating, and electricity. The distribution between the two sectors is shown in Table 2-3.

TABLE 2-2. SUMMARY OF THE TOTAL BOILER POPULATION BY FUEL USED

Fuel	Number of boilers	Total capacity,[a] MW thermal	(10^6 Btu/h)
Coal	214,400	239,110	(815,830)
Residual oil	389,104	358,570	(1,223,800)
Distillate oil	244,206	127,040	(433,600)
Natural gas	954,350	588,590	(2,008,800)

[a] Throughout this section totals for capacity do not always agree because figures are rounded.

TABLE 2-3. DISTRIBUTION OF NONUTILITY BOILERS BY SECTOR

Sector	Number of boilers	Total capacity, MW thermal	(10^6 Btu/h)
Commercial	1,295,130	402,780	(1,374,690)
Industrial	506,930	910,480	(3,107,440)

Because the size of a boiler can directly relate to the total quantity of pollutants discharged and the feasibility and economics of control, it is necessary to distribute the total industrial/commercial population by size. Table 2-4 presents such a display. As shown in this table, 1,094,000 MW thermal (3,733,800 x 10^6 Btu/h), or 83 percent of the industrial/commercial boiler capacity, is comprised of units whose size is less than 73.25 MW thermal (250 x 10^6 Btu/h), the lower limit for the existing New Source Performance Standards for boilers.

TABLE 2-4. DISTRIBUTION OF COMMERCIAL/INDUSTRIAL BOILERS BY SIZE

Size, MW thermal (10^6 Btu/h)	Number of boilers	Total capacity, MW thermal (10^6 Btu/h)	
Equal to or under 0.1 (equal to or under 0.4)	970,980	69,180	(236,100)
Over 0.1 to 0.4 (over 0.4 to 1.5)	568,415	143,820	(490,700)
Over 0.4 to 2.9 (over 1.5 to 10)	208,659	240,270	(820,000)
Over 2.9 to 7.3 (over 10 to 25)	25,081	126,770	(432,600)
Over 7.3 to 14.7 (over 25 to 50)	16,483	178,350	(608,700)
Over 14.7 to 29.3 (over 50 to 100)	6,840	147,380	(503,000)
Over 29.3 to 73.3 (over 100 to 250)	4,266	185,160	(632,000)
Over 73.3 to 146.5 (over 250 to 500)	1,018	98,280	(335,400)
Over 146.5 to 439.5 (over 500 to 1500)	253	56,080	(191,400)
Over 439.5 (over 1500)	65	68,050	(232,200)

A basic and important way to classify boilers is according to heat transfer configuration, i.e., water-tube, fire-tube, and cast iron. In water-tube boilers, the water being heated flows through tubes and the hot gases circulate outside of the tubes. In fire-tube boilers, the opposite is true. In cast iron boilers, the gas is also contained inside the tubes that are surrounded by the water being heated, but the units are constructed of cast iron rather than steel. Classification by type is important because water-tube boilers are generally much larger than fire-tube or cast iron boilers. The potential emissions are different for the various types of boilers.

Tables 2-5 through 2-7 provide the distributions for the three types of boilers according to the size range and fuel used. It will be noted that Table 2-5 provides a subcategorization for coal-fired units according to firing mechanism. In Tables 2-8 through 2-13, these distributions are presented individually for the commercial sector and the industrial sector.

Table 2-14 summarizes the results and clearly indicates that water-tube boilers represent over half the total capacity. Furthermore, the average size of water-tube boilers exceeds that of fire-tube boilers by more than 10 times.

In summary, the derived data indicate the following characteristics of the boiler population:

- Natural gas is the predominant fuel, accounting for 45 percent of the capacity.
- Ranking of the other fuels by capacity is residual oil at 27 percent, coal at 18 percent, and distillate oil at 10 percent.
- Distribution of the industrial/commercial boiler population is 69 percent of the capacity in industrial applications and 31 percent in commercial applications.
- Forty percent of the industrial/commercial boiler capacity is in the range of 1 to 73 MW thermal. Seventeen percent of the capacity is above 73 MW thermal, and 44 percent is below 7 MW thermal.

TABLE 2-5. DISTRIBUTION OF U.S. WATER-TUBE BOILERS BY CAPACITY AND FUEL TYPE

	Capacity range, MW thermal (10^6 Btu/h)									
Fuel	0.1 to 0.4 (0.4 to 1.5)	0.4 to 2.9 (1.5 to 10)	2.9 to 7.3 (10 to 25)	7.1 to 14.7 (25 to 50)	14.7 to 29.3 (50 to 100)	29.3 to 73.3 (100 to 250)	73.3 to 146.5 (250 to 500)	146.5 to 439.5 (500 to 1500)	439.5 (1500)	Totals
Pulverized coal										
Number of units	0	0	0	0	0	467	191	64	11	733
Total capacity, MW thermal (10^6 Btu/h)						20,510 (70,000)	18,460 (63,000)	13,980 (47,700)	7,740 (26,400)	60,690 (207,100)
Spreader-stoker coal										
Number of units	0	103	142	521	343	506	83	9	3	1,700
Total capacity, MW thermal (10^6 Btu/h)		150 (500)	710 (2,400)	5,830 (19,900)	7,440 (25,400)	21,590 (73,700)	7,500 (25,600)	2,260 (7,700)	1,850 (6,300)	47,330 (161,500)
Underfeed-stoker coal										
Number of units	532	928	657	1,509	950	180	38	5	1	4,800
Total capacity, MW thermal (10^6 Btu/h)	150 (500)	1,410 (4,800)	3,230 (11,000)	16,760 (57,200)	20,800 (71,000)	7,530 (25,700)	3,490 (11,900)	1,110 (3,800)	910 (3,100)	55,390 (189,000)
Overfeed-stoker coal										
Number of units	28	114	89	402	249	98	26	3	1	1,062
Total capacity, MW thermal (10^6 Btu/h)	10 (30)	180 (600)	440 (1,500)	4,430 (15,100)	5,370 (18,300)	3,780 (12,900)	2,350 (8,000)	730 (2,500)	620 (2,100)	17,910 (61,030)
Residual oil										
Number of units	1,173	3,215	2,731	5,022	2,205	1,237	300	62	8	15,953
Total capacity, MW thermal (10^6 Btu/h)	410 (1,400)	4,830 (16,500)	13,010 (44,400)	53,560 (182,800)	47,520 (162,200)	53,320 (182,000)	29,240 (99,800)	13,890 (47,400)	5,630 (19,200)	221,410 (755,700)
Distillate oil										
Number of units	2,928	2,958	659	914	298	202	41	7	1	8,008
Total capacity, MW thermal (10^6 Btu/h)	1,030 (3,500)	3,460 (11,800)	2,960 (10,100)	9,310 (31,800)	6,710 (22,900)	8,850 (30,200)	4,250 (14,500)	1,520 (5,200)	670 (2,300)	38,760 (132,300)
Natural gas										
Number of units	2,414	3,616	2,535	4,863	2,795	1,586	339	103	40	18,291
Total capacity, MW thermal (10^6 Btu/h)	850 (2,900)	4,920 (16,800)	12,630 (43,100)	52,710 (179,900)	59,540 (203,200)	69,580 (237,500)	32,990 (112,600)	22,590 (77,100)	50,630 (172,800)	306,440 (1,045,900)
Total all fuels										
Number of units	7,075	10,934	6,813	13,231	6,840	4,266	1,018	253	65	50,495
Total capacity, MW thermal (106 Btu/h)	2,450 (8,330)	14,950 (51,000)	32,980 (112,500)	142,600 (486,700)	147,380 (503,000)	185,160 (632,000)	98,280 (335,400)	56,080 (191,400)	68,050 (232,200)	747,930 (2,552,530)

TABLE 2-6. DISTRIBUTION OF U.S. FIRE-TUBE BOILERS BY CAPACITY AND FUEL TYPE

Fuel	Size range, MW thermal (10^6 Btu/h)				
	0.1 to 0.4 (0.4 to 1.5)	0.4 to 2.9) (1.5 to 10)	2.9 to 7.3 (10 to 25)	7.3 to 14.7 (25 to 50)	Totals
Coal					
Number of units	19,227	5,210	1,533	358	26,328
Total capacity, MW	5,630	8,790	7,850	3,930	26,200
thermal (10^6 Btu/h)	(19,200)	(30,000)	(26,800)	(13,400)	(89,400)
Residual oil					
Number of units	46,267	21,511	5,072	833	73,683
Total capacity, MW	13,570	34,630	26,050	9,140	83,390
thermal (10^6 Btu/h)	(46,300)	(118,200)	(88,900)	(31,200)	(284,600)
Distillate oil					
Number of units	30,191	14,089	3,318	543	48,141
Total capacity, MW	8,850	22,680	17,050	5,980	54,560
thermal (10^6 Btu/h)	(30,200)	(77,400)	(58,200)	(20,400)	(186,200)
Natural gas					
Number of units	83,483	33,577	8,345	1,518	126,923
Total capacity, MW	24,470	54,620	42,840	16,700	138,630
thermal (10^6 Btu/h)	(83,500)	(186,400)	(146,200)	(57,000)	(473,100)
Total all fuels					
Number of units	179,168	74,387	18,268	3,252	275,075
Total capacity, MW	52,520	120,720	93,790	35,750	302,780
thermal (10^6 Btu/h)	(179,200)	(412,000)	(320,100)	(122,000)	(1,033,300)

TABLE 2-7. DISTRIBUTION OF U.S. CAST IRON BOILERS BY CAPACITY AND FUEL TYPE

Fuel	Size range, MW thermal (10^6 Btu/h) <0.1 (<0.4)	 0.1 to 0.4 (0.4 to 1.5)	 0.4 to 2.9 (1.5 to 10)	 Total
Coal				
Number of units	113,287	46,760	19,782	179,829
MW thermal input	6,010	12,310	13,270	31,590
(10^6 Btu/h)	(20,500)	(42,000)	(45,300)	(107,800)
Residual oil				
Number of units	203,569	71,614	24,285	299,468
MW thermal input	15,030	16,090	22,650	53,770
(10^6 Btu/h)	(51,300)	(54,900)	(77,300)	(183,500)
Distillate oil				
Number of units	127,833	44,979	15,245	188,057
MW thermal input	9,430	10,080	14,210	33,720
(10^6 Btu/h)	(32,200)	(34,400)	(48,500)	(115,100)
Natural gas				
Number of units	526,291	218,819	64,026	809,136
MW thermal input	38,710	50,340	54,470	143,520
(10^6 Btu/h)	(132,100)	(171,800)	(185,900)	(489,800)
Total all fuel				
Number of units	970,980	382,172	123,338	1,476,490
MW thermal input	69,180	88,820	104,600	262,600
(10^6 Btu/h)	(236,100)	(303,100)	(357,000)	(896,200)

TABLE 2-8. DISTRIBUTION OF U.S. WATER-TUBE COMMERCIAL BOILERS BY CAPACITY AND FUEL TYPE

Fuel	Capacity range, MW thermal (10^6 Btu/h)									Totals
	0.1 to 0.4 (0.4 to 1.5)	0.4 to 2.9 (1.5 to 10)	2.9 to 7.3 (10 to 25)	7.3 to 14.7 (25 to 50)	14.7 to 29.3 (50 to 100)	29.3 to 73.3 (100 to 250)	73.3 to 146.5 (250 to 500)	146.5 to 439.5 (500 to 1500)	439.5 (1500)	
Pulverized coal										
Number of units	0	0	0	0	0	14	0	0	0	14
Total capacity, MW thermal (10^6 Btu/h)						615 (2,100)				615 (2,100)
Spreader-stoker coal										
Number of units	0	57	53	146	58	30	7	0	0	351
Total capacity, MW thermal (10^6 Btu/h)		80 (280)	260 (890)	1,630 (5,570)	1,265 (4,320)	1,295 (4,420)	600 (2,050)			5,130 (17,530)
Underfeed-stoker coal										
Number of units	372	510	243	423	162	11	3	0	0	1,724
Total capacity, MW thermal (10^6 Btu/h)	105 (350)	775 (2,640)	1,195 (4,070)	4,690 (16,020)	3,535 (12,070)	450 (1,540)	280 (950)			11,030 (37,640)
Overfeed-stoker coal										
Number of units	20	63	33	113	42	5	2	0	0	278
Total capacity, MW thermal (10^6 Btu/h)	5 (20)	100 (330)	160 (560)	1,240 (4,230)	915 (3,110)	225 (770)	190 (640)			2,835 (9,660)
Residual oil										
Number of units	399	772	710	1,406	551	198	39	6	0	4,081
Total capacity, MW thermal (10^6 Btu/h)	140 (480)	1,160 (3,960)	3,380 (11,540)	15,000 (51,180)	11,880 (40,550)	8,530 (29,120)	3,800 (12,970)	1,390 (4,740)		45,280 (154,540)
Distillate oil										
Number of units	1552	1,183	204	302	107	32	16	3	0	3,399
Total capacity, MW thermal (10^6 Btu/h)	550 (1860)	1,380 (4,720)	920 (3,130)	3,070 (10,490)	2,415 (8,240)	2,480 (8,460)	1,700 (5,800)	655 (2,240)		13,170 (44,940)
Natural gas										
Number of units	893	723	330	535	280	143	37	7	4	2,952
Total capacity, MW thermal (10^6 Btu/h)	310 (1070)	985 (3,360)	1,640 (5,600)	5,800 (19,790)	5,955 (2C,320)	6,260 (21,370)	3,630 (12,390)	1,580 (5,400)	5,065 (17,280)	31,225 (106,560)
Total all fuels										
Number of units	3236	3,308	1,573	2,925	1,200	433	104	16	4	12,790
Total capacity, MW thermal (106 Btu/h)	1110 (3780)	4,480 (15,290)	7,555 (25,790)	31,430 (107,280)	25,965 (88,610)	19,855 (67,780)	10,200 (34,800)	3,625 (12,380)	5,065 (17,280)	109,205 (372,990)

TABLE 2-9. DISTRIBUTION OF U.S. WATER-TUBE INDUSTRIAL BOILERS BY CAPACITY AND FUEL TYPE

	Capacity range, MW thermal (10^6 Btu/h)									
Fuel	0.1 to 0.4 (0.4 to 1.5)	0.4 to 2.9 (1.5 to 10)	2.9 to 7.3 (10 to 25)	7.3 to 14.7 (25 to 50)	14.7 to 29.3 (50 to 100)	29.3 to 73.3 (100 to 250)	73.3 to 146.5 (250 to 500)	146.5 to 439.5 (500 to 1500)	439.5 (1500)	Totals
Pulverized coal										
Number of units	0	0	0	0	0	453	191	64	11	719
Total capacity, MW thermal (10^6 Btu/h)						19,895 (67,900)	18,460 (63,000)	13,980 (47,700)	7,740 (26,400)	60,075 (205,000)
Spreader-stoker coal										
Number of units	0	46	89	375	285	474	76	9	3	1,357
Total capacity, MW thermal (10^6 Btu/h)		70 (220)	450 (1,510)	4,200 (14,330)	6,175 (21,080)	20,295 (69,280)	6,900 (23,550)	2,260 (7,700)	1,850 (6,300)	42,200 (143,970)
Underfeed-stoker coal										
Number of units	160	418	414	1,086	798	169	35	5	1	3,076
Total capacity, MW thermal (10^6 Btu/h)	45 (150)	635 (2,160)	2,035 (6,930)	12,070 (41,180)	17,265 (58,930)	7,080 (24,160)	3,210 (10,950)	1,110 (3,800)	910 (3,100)	44,360 (151,360)
Overfeed-stoker coal										
Number of units	8	51	56	289	207	85	24	3	1	724
Total capacity, MW thermal (10^6 Btu/h)	5 (10)	80 (270)	280 (940)	3,190 (10,870)	4,455 (18,190)	3,555 (12,130)	2,160 (7,360)	730 (2,500)	620 (2,100)	15,075 (51,370)
Residual oil										
Number of units	774	2,443	2,021	3,616	1,654	1,039	261	56	8	11,872
Total capacity, MW thermal (10^6 Btu/h)	270 (920)	3,670 (12,540)	9,630 (32,860)	38,560 (131,620)	35,640 (121,650)	44,790 (152,880)	25,440 (86,830)	12,500 (42,660)	5,630 (19,200)	176,130 (601,160)
Distillate oil										
Number of units	1376	1,775	455	612	191	170	25	4	1	4,609
Total capacity, MW thermal (10^6 Btu/h)	480 (1640)	2,080 (7,080)	2,040 (6,970)	6,240 (21,310)	4,295 (14,660)	6,370 (21,740)	2,550 (8,700)	865 (2,960)	670 (2,300)	25,590 (87,360)
Natural gas										
Number of units	1521	2,893	2,205	4,328	2,615	1,443	302	96	36	15,339
Total capacity, MW thermal (10^6 Btu/h)	540 (1830)	3,935 (13,440)	10,990 (37,500)	46,910 (160,110)	58,585 (182,880)	63,120 (216,130)	29,160 (100,210)	21,010 (71,700)	45,565 (155,520)	275,215 (939,320)
Total all fuels										
Number of units	3839	7,626	5,240	10,306	5,640	3,833	914	237	61	37,696
Total capacity, MW thermal (106 Btu/h)	1340 (4550)	10,470 (35,710)	25,425 (86,710)	111,170 (379,420)	121,415 (414,390)	165,105 (564,220)	88,080 (300,600)	52,455 (179,020)	62,985 (214,920)	638,645 (2,179,540)

TABLE 2-10. DISTRIBUTION OF U.S. COMMERCIAL FIRE-TUBE BOILERS BY CAPACITY AND FUEL TYPE

Fuel	Size range, MW thermal (10^6 Btu/h)				
	0.1 to 0.4 (0.4 to 1.5)	0.4 to 2.9 (1.5 to 10)	2.9 to 7.3 (10 to 25)	7.3 to 14.7 (25 to 50)	Totals
Coal					
Number of units	13,459	2,866	567	100	16,992
Total capacity, MW thermal (10^6 Btu/h)	3,940 (13,500)	4,830 (16,500)	2,900 (9,900)	1,100 (3,800)	12,770 (43,700)
Residual oil					
Number of units	15,731	5,163	1,319	233	22,446
Total capacity, MW thermal (10^6 Btu/h)	4,610 (15,700)	8,310 (28,400)	6,770 (23,100)	2,560 (8,700)	22,250 (75,900)
Distillate oil					
Number of units	16,001	5,636	1,029	179	22,845
Total capacity, MW thermal (10^6 Btu/h)	4,690 (16,000)	9,070 (31,000)	5,290 (18,000)	1,970 (6,700)	21,020 (71,700)
Natural gas					
Number of units	30,889	6,715	1,085	167	38,856
Total capacity, MW thermal (10^6 Btu/h)	9,050 (30,900)	10,920 (37,300)	5,570 (19,000)	1,840 (6,300)	27,380 (93,500)
Total all fuels					
Number of units	76,080	20,380	4,000	679	101,139
Total capacity, MW thermal (10^6 Btu/h)	22,290 (76,100)	33,130 (113,200)	20,530 (70,000)	7,470 (25,500)	83,420 (284,800)

TABLE 2-11. DISTRIBUTION OF U.S. INDUSTRIAL FIRE-TUBE BOILERS BY CAPACITY AND FUEL TYPE

Fuel	Size range, MW thermal (10^6 Btu/h)				
	0.1 to 0.4 (0.4 to 1.5)	0.4 to 2.9 (1.5 to 10)	2.9 to 7.3 (10 to 25)	7.3 to 14.7 (25 to 50)	Totals
Coal					
Number of units	5,768	2,344	966	258	9,336
Total capacity, MW thermal (10^6 Btu/h)	1,690 (5,700)	3,960 (13,500)	4,950 (16,900)	2,830 (9,600)	13,430 (45,700)
Residual oil					
Number of units	30,536	16,348	3,753	600	51,237
Total capacity, MW thermal (10^6 Btu/h)	8,960 (30,600)	26,320 (89,800)	19,280 (65,800)	6,580 (22,500)	61,140 (208,700)
Distillate oil					
Number of units	14,190	8,453	2,289	364	25,296
Total capacity, MW thermal (10^6 Btu/h)	4,160 (14,200)	13,610 (46,400)	11,760 (40,200)	4,010 (13,700)	33,540 (114,500)
Natural gas					
Number of units	52,594	26,862	7,260	1,351	88,067
Total capacity, MW thermal (10^6 Btu/h)	15,420 (52,600)	43,700 (149,100)	37,270 (127,200)	9,230 (50,700)	111,250 (379,600)
Total all fuels					
Number of units	103,088	54,007	14,268	2,573	173,936
Total capacity, MW thermal (10^6 Btu/h)	30,230 (103,100)	87,590 (298,800)	73,260 (250,100)	28,280 (96,500)	219,360 (748,500)

Table 2-12. DISTRIBUTION OF U.S. COMMERCIAL/INSTITUTIONAL CAST IRON BOILERS BY CAPACITY AND FUEL TYPE

Fuel	Size range, MW thermal (10^6 Btu/h)			
	<0.1 (<0.4)	0.1 to 0.4 (0.4 to 1.5)	0.4 to 2.9 (1.5 to 10)	Total
Coal				
Number of units	90,630	37,408	15,826	143,864
MW thermal input	4,810	9,840	10,610	25,260
(10^6 Btu/h)	(16,400)	(33,600)	(36,200)	(86,200)
Residual oil				
Number of units	162,855	57,291	19,428	239,574
MW thermal input	12,010	12,860	18,140	43,010
(10^6 Btu/h)	(41,000)	(43,900)	(61,900)	(186,800)
Distillate oil				
Number of units	102,266	35,983	12,196	150,445
MW thermal input	7,530	8,090	11,370	26,990
(10^6 Btu/h)	(25,700)	(27,600)	(38,800)	(92,100)
Natural gas				
Number of units	421,033	175,055	51,221	647,309
MW thermal input	30,970	40,260	43,570	114,800
(10^6 Btu/h)	(105,700)	(137,400)	(148,700)	(391,800)
Total all fuel				
Number of units	776,784	305,737	98,671	1,181,192
MW thermal input	55,320	71,050	83,690	210,060
(10^6 Btu/h)	(188,800)	(242,500)	(285,600)	(716,900)

TABLE 2-13. DISTRIBUTION OF U.S. INDUSTRIAL CAST IRON BOILERS BY CAPACITY AND FUEL TYPE

Fuel	Size range, MW thermal (10^6 Btu/h)			
	<0.1 (<0.4)	0.1 to 0.4 (0.4 to 1.5)	0.4 to 2.9 (1.5 to 10)	Totals
Coal				
Number of units	22,657	9,352	3,956	35,965
Total capacity, MW thermal (10^6 Btu/h)	1,200 (4,100)	2,460 (8,400)	2,670 (9,100)	6,330 (21,600)
Residual oil				
Number of units	40,714	14,323	4,857	59,894
Total capacity, MW thermal (10^6 Btu/h)	3,020 (10,300)	3,220 (11,000)	4,540 (15,500)	10,780 (36,800)
Distillate oil				
Number of units	25,567	8,996	3,049	37,612
Total capacity, MW thermal (10^6 Btu/h)	1,880 (6,400)	2,020 (6,900)	2,840 (9,700)	6,740 (23,000)
Natural gas				
Number of units	105,258	43,764	12,805	161,827
Total capacity, MW thermal (10^6 Btu/h)	7,740 (26,400)	10,080 (34,400)	10,900 (37,200)	28,720 (98,000)
Total all fuels				
Number of units	194,196	76,435	24,667	295,298
Total capacity, MW thermal (10^6 Btu/h)	13,840 (47,200)	17,780 (60,700)	20,950 (71,500)	52,570 (179,400)

TABLE 2-14. BOILER POPULATION DISTRIBUTED BY HEAT-TRANSFER CONFIGURATION

Heat transfer configuration	Number of boilers	Total capacity, MW thermal	(10^6 Btu/h)
Water-tube	50,495	747,930	(2,552,500)
Fire-tube	275,075	302,780	(1,033,300)
Cast iron	1,476,490	262,600	(896,200)

- Distribution of the industrial commercial boiler capacity by the three major types is 57 percent water-tube, 23 percent fire-tube, and 20 percent cast iron.

Given the significance of water-tube boilers, it is appropriate to examine further details of the population.

Based on sales data from the ABMA and HI, it was determined that about 20 percent of the water-tube boiler capacity currently in place is less than 7 years old. (The sales data from ABMA were available only for the past 7 years). About 25 percent of the current capacity of fire-tube and cast iron boilers is less than 10 years old. About 62 percent of industrial/commercial water-tube boiler capacity is field-erected. The rest are package units (i.e., fabricated in the shop and transported in one piece to the plant site). In contrast, all fire-tube and cast iron boilers are package units. Tables 2-15 and 2-16 provide a distribution of the water-tube boilers by size and fuel type for the field-erected and package units. Although there are three times as many package units, these only represent a third of the total capacity.

The majority of the total water-tube boiler capacity is represented by boilers below 73.3 MW thermal (250 x 10^6 Btu/h), the present lower limit for units subject to NSPS. The distribution by size, (excerpted from Table 2-5) is:

Size, MW thermal (10^6 Btu/h)	Total capacity, MW thermal (10^6 Btu/h)
Equal to or under 7.3 (equal to or under 25)	50,380 (171,800)
Over 7.3 - 14.7 (over 25 - 50)	142,600 (486,700)
Over 14.7 - 29.3 (over 50 - 100)	147,380 (503,000)
Over 29.3 - 73.3 (over 100 - 250)	185,160 (632,000)
Over 73.3 (over 250)	222,410 (759,000)

Only 6.7 percent of the total water-tube capacity is below 7.3 MW thermal (25 x 10^6 Btu/h). Water-tube units below 73.3 MW thermal account for nearly 49 percent of the boilers not presently covered by NSPS.

TABLE 2-15. DISTRIBUTION OF U.S. FIELD-ERECTED WATER-TUBE BOILERS BY CAPACITY AND FUEL TYPE

	Capacity range, MW thermal (10^6 Btu/h)									Totals
Fuel	0.1 to 0.4 (0.4 to 1.5)	0.4 to 2.9 (1.5 to 10)	2.9 to 7.3 (10 to 25)	7.3 to 14.7 (25 to 50)	14.7 to 29.3 (50 to 100)	29.3 to 73.3 (100 to 250)	73.3 to 146.5 (250 to 500)	146.5 to 439.5 (500 to 1500)	439.5 (1500)	
Pulverized coal										
Number of units	0	0	0	0	0	350	190	64	11	615
Total capacity, MW thermal (10^6 Btu/h)						15,380 (52,500)	18,370 (62,700)	13,980 (47,700)	7,740 (26,400)	55,470 (189,300)
Spreader-stoker coal										
Number of units	0	0	43	157	120	379	82	9	3	793
Total capacity, MW thermal (10^6 Btu/h)			210 (700)	1,760 (6,000)	2,610 (8,900)	16,200 (55,300)	7,410 (25,300)	2,260 (7,700)	1,850 (6,300)	32,300 (110,200)
Underfeed-stoker coal										
Number of units	0	0	197	453	333	135	37	5	1	1,161
Total capacity, MW thermal (10^6 Btu/h)			970 (3,300)	5,040 (17,200)	7,470 (25,500)	5,650 (19,300)	3,400 (11,600)	1,110 (3,800)	910 (3,100)	24,550 (83,800)
Overfeed-stoker coal										
Number of units	0	0	26	120	87	67	25	3	1	329
Total capacity, MW thermal (10^6 Btu/h)			120 (400)	1,320 (4,500)	1,880 (6,400)	2,840 (9,700)	2,260 (7,700)	730 (2,500)	620 (2,100)	9,770 (33,300)
Residual oil										
Number of units	0	0	819	1,507	771	928	298	62	8	4,393
Total capacity, MW thermal (10^6 Btu/h)			3,900 (13,300)	16,060 (54,800)	16,640 (56,800)	39,990 (136,500)	28,950 (96,800)	13,890 (47,400)	5,630 (19,200)	125,060 (426,800)
Distillate oil										
Number of units	0	0	197	274	105	151	40	7	1	775
Total capacity, MW thermal (10^6 Btu/h)			880 (3,000)	2,780 (9,500)	2,340 (8,000)	6,620 (22,600)	4,160 (14,200)	1,520 (5,200)	670 (2,300)	18,970 (64,800)
Natural gas										
Number of units	0	0	760	1,459	979	1,189	337	103	40	4,867
Total capacity, MW thermal (10^6 Btu/h)			3,780 (12,900)	15,820 (54,000)	20,830 (71,100)	52,180 (178,100)	32,700 (111,600)	22,590 (77,100)	50,630 (172,800)	178,530 (677,600)
Total all fuels										
Number of units	0	0	2,042	3,970	2,395	3,199	1,009	253	65	12,933
Total capacity, MW thermal (106 Btu/h)			9,860 (33,600)	42,780 (146,000)	51,770 (176,700)	138,860 (474,000)	97,250 (331,900)	56,080 (191,400)	68,050 (232,200)	464,650 (1,585,800)

TABLE 2-16. DISTRIBUTION OF U.S. PACKAGE WATER-TUBE BOILERS BY CAPACITY AND FUEL TYPE

Fuel	Capacity range, MW thermal (10^6 Btu/h)									Totals
	0.1 to 0.4 (0.4 to 1.5)	0.4 to 2.9 (1.5 to 10)	2.9 to 7.3 (10 to 25)	7.3 to 14.7 (25 to 50)	14.7 to 29.3 (50 to 100)	29.3 to 73.3 (100 to 250)	73.3 to 146.5 (250 to 500)	146.5 to 439.5 (500 to 1500)	439.5 (1500)	
Pulverized coal										
Number of units	0	0	0	0	0	117	1	0	0	118
Total capacity, MW thermal (10^6 Btu/h)						5,130 (17,500)	90 (300)			5,220 (17,800)
Spreader-stoker coal										
Number of units	0	103	99	164	223	125	1	0	0	915
Total capacity, MW thermal (10^6 Btu/h)		150 (500)	500 (1,700)	4,070 (13,900)	4,830 (16,500)	5,390 (18,400)	90 (300)			15,030 (51,300)
Underfeed-stoker coal										
Number of units	532	928	460	1,056	617	45	1	0	0	3,639
Total capacity, MW thermal (10^6 Btu/h)	150 (500)	1,410 (4,800)	2,260 (7,700)	11,720 (40,000)	13,330 (45,500)	1,880 (6,400)	90 (300)			30,840 (105,200)
Overfeed-stoker coal										
Number of units	28	114	63	282	162	23	1	0	0	673
Total capacity, MW thermal (10^6 Btu/h)	10 (30)	180 (600)	320 (1,100)	3,110 (10,600)	3,490 (11,900)	940 (3,200)	90 (300)			8,140 (27,730)
Residual oil										
Number of units	1173	3,215	1,912	3,515	1,434	309	2	0	0	11,560
Total capacity, MW thermal (10^6 Btu/h)	410 (1400)	4,830 (16,500	9,110 (31,100)	37,500 (128,000)	30,880 (105,400)	13,330 (45,500)	290 (1000)			96,350 (328,900)
Distillate oil										
Number of units	2928	2,958	462	640	193	51	1	0	0	7,233
Total capacity, MW thermal (10^6 Btu/h)	1030 (3500)	3,460 (11,800)	2,080 (7,100)	6,530 (22,300)	4,370 (14,900)	2,230 (7,600)	90 (300)			19,790 (67,500)
Natural gas										
Number of units	2414	3,616	1,775	3,404	1,816	397	2	0	0	13,424
Total capacity, MW thermal (10^6 Btu/h)	850 (2900)	4,920 (16,800)	8,850 (30,200)	36,890 (125,900)	38,710 (132,100)	17,400 (59,400)	290 (1000)			107,910 (368,300)
Total all fuels										
Number of units	7075	10,934	4,771	9,261	4,445	1,067	9	0	0	37,562
Total capacity, MW thermal (10^6 Btu/h)	2450 (8330)	14,950 (51,000)	23,120 (78,900)	99,820 (340,700)	95,610 (326,300)	46,300 (158,000)	1030 (3500)			283,280 (966,730)

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The capacity represented by boilers between 7.3 and 73.3 MW thermal (25 and 250 x 10^6 Btu/h) is large for both field-erected and package water-tube boilers. Approximately 93.5 percent of the capacity of package boilers is in this range. For field-erected boilers, the distribution is:

Size, MW thermal (10^6 Btu/h)	Total capacity, %
Equal to or under 7.2 (equal to or under 25)	2.1
Over 7.2 - 73.2 (25 - 250)	50.3
Over 73.2 (over 250)	47.6

The distribution of capacity by fuel for all water-tube boilers (excerpted from Table 2-5) is:

Fuel	Total capacity, MW thermal (10^6 Btu/h)
Natural gas	306,440 (1,045,900)
Residual oil	221,410 (755,700)
Coal	181,320 (618,600)
Distillate oil	38,760 (132,300)

Water-tube boilers account for only 27 percent of the overall capacity of commercial units; the balance comes from fire-tube and cast iron boilers.

In summary, the industrial/commercial water-tube boiler population has the following characteristics:

- It represents the majority of total capacity.
- It represents the fewest boilers.
- The average boiler size is the largest of the three types.
- The majority of the total water-tube boiler capacity is field-erected.
- Most units are industrial rather than commercial.

Table 2-6 presented the total estimated fire-tube capacity by size and fuel. Only 11.8 percent of this capacity is provided by boilers larger than 7.3 MW thermal (25 x 10^6 Btu/h).

Most fire-tube boilers have a capacity between 0.4 and 7.3 MW thermal (1.5 and 25 x 10^6 Btu/h). Water-tube units also account for some capacity in the small size ranges; but for boilers under 7.3 MW thermal (25 x 10^6 Btu/h), fire-tube units represent five times as much capacity as water-tube boilers. Thus boilers with different heat transfer configurations predominate in different size ranges.

Tables 2-10 and 2-11 presented the distribution of fire-tube capacity between commercial and industrial boilers. Approximately 21 percent of the total commercial boiler capacity comes from fire-tube units. Most fire-tube boilers, however, are used by industry.

The total capacity of cast iron boilers was presented by size and fuel in Table 2-7. All industrial/commercial units below 0.1 MW thermal (0.4 x 10^6 Btu/h) are cast iron. Above this size through 2.9 MW thermal (10 x 10^6 Btu/h), cast iron and fire-tube boilers overlap considerably. No cast iron units are larger than 2.9 MW thermal (10 x 10^6 Btu/h).

Tables 2-12 and 2-13 presented estimates of cast iron boiler capacity in commercial and industrial applications. The tables show that 80 percent of all cast iron boiler capacity are used commercially. It should be noted that this ratio was based on estimates by Walden and could not be verified independently in this study. The same is true of the fire-tube and water-tube boiler distributions discussed previously. In all cases, the ratio of commercial to industrial capacity was assumed in this study to be independent of fuel. This assumption may have introduced errors in the industrial/commercial distribution but would not significantly affect the overall size and fuel distributions.

The classification of total boiler population by type of industry is an important parameter. Sales data from ABMA for water-tube boilers sold during the period 1966 to 1977 are classified by the Standard Industrial Classification (SIC). Table 2-17

TABLE 2-17. DISTRIBUTION BY SIC OF WATER-TUBE BOILERS SOLD IN PERIOD 1965 THROUGH 1977

SIC	Industry	Fuel	No. of boilers	Capacity MW thermal input (10^6 Btu/h)	Percent by industry
00	Nonmanufacturing	Coal	26	482 (1,644)	
		Oil	349	8,824 (30,116)	
		Gas	828	12,894 (44,008)	
		Sub total	1,203	22,200 (75,768)	15.2
15	Offices, shopping centers, malls	Oil	2	234 (800)	
		Gas	10	293 (1,000)	
		Sub total	12	527 (1,800)	0.4
20	Food	Coal	18	1,116 (3,810)	
		Oil	140	2,771 (9,457)	
		Gas	498	9,344 (31,892)	
		Sub total	656	13,232 (45,159)	9.1
22	Textile mills	Coal	15	533 (1,820)	
		Oil	124	1,912 (6,526)	
		Gas	266	3,942 (13,453)	
		Sub total	405	6,387 (21,799)	4.4
24	Lumber and wood products	Coal	3	26 (90)	
		Oil	33	585 (1,996)	
		Gas	37	593 (2,023)	
		Sub total	73	1,204 (4,109)	0.8
26	Paper, allied products	Coal	14	1,393 (4,754)	
		Oil	126	3,911 (13,350)	
		Gas	114	3,999 (13,647)	
		Sub total	254	9,303 (31,751)	6.4
28	Chemicals, allied products	Coal	48	3,316 (11,318)	
		Oil	305	9,334 (31,856)	
		Gas	530	14,656 (50,019)	
		Sub total	883	27,306 (93,193)	18.7
29	Petroleum refining, related industries	Coal	2	44 (150)	
		Oil	143	6,336 (21,625)	
		Gas	213	7,396 (25,243)	
		Sub total	358	13,776 (47,018)	9.4
30	Rubber products	Oil	53	1,012 (3,453)	
		Gas	104	1,750 (5,972)	
		Sub total	157	2,762 (9,425)	1.9
33	Primary metal	Coal	9	158 (540)	
		Oil	36	1,064 (3,630)	
		Gas	110	3,097 (10,571)	
		Sub total	155	4,319 (14,741)	3.0
37	Transportation	Coal	26	1,272 (4,340)	
		Oil	58	1,469 (5,015)	
		Gas	133	2,840 (9,694)	
		Sub total	217	5,581 (19,049)	3.8
39	Miscellaneous manufacturing	Coal	29	1,097 (3,743)	
		Oil	211	4,664 (15,919)	
		Gas	436	9,518 (32,484)	
		Sub total	676	15,279 (52,146)	10.5
65	Apartments	Gas	11	129 (440)	
		Sub total	11	129 (440)	Nil
72	Boiler rentals	Oil	38	1,152 (3,933)	
		Gas	78	2,263 (7,725)	
		Sub total	116	3,416 (11,658)	2.3
80	Hospitals, medical centers, homes	Coal	21	237 (810)	
		Oil	288	2,851 (9,731)	
		Gas	781	7,316 (24,967)	
		Sub total	1,090	10,404 (35,508)	7.1
82	Schools and universities	Coal	32	881 (3,006)	
		Oil	174	3,136 (10,704)	
		Gas	368	6,066 (20,704)	
		Sub total	574	10,083 (34,414)	6.9
		TOTAL	6,840	145,908 (497,978)	99.9

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presents a tabulation of the ABMA sales data by fuel type and SIC code. Boilers in the nonmanufacturing sector (i.e., commercial/institutional) are denoted with a SIC code of zero.

As the data indicate, the chemical, petroleum refinery, and food industries are the largest purchasers of new water-tube boilers, and the chemical industry purchased twice the capacity of the other two industries.

2.3 FUEL CONSUMPTION

The major fuels consumed by industrial and commercial boilers are coal, residual oil, distillate oil, and natural gas. Among the other fuels burned are wood wastes, liquified petroleum gas, asphalt, and kerosene. Since the four major fuels constitute the vast majority of all fuels burned (estimated at greater than 90%), and since the use of other fuels is site-specific and difficult to document, the consumption figures of only the four major fuels were compiled and analyzed.

Figures for the consumption of fuel in industrial/commercial boilers were derived from statistical reports compiled by the Department of Energy. The procedure is fully described in Appendix D.

The summary presented in Table 2-18 shows that gas is the most widely used boiler fuel, and that residual oil is burned in industrial/commercial boilers in greater quantities than coal.

TABLE 2-18. ANNUAL FUEL CONSUMPTION BY INDUSTRIAL/COMMERCIAL BOILERS

Fuel type	Total energy, 10^{15} J	(10^{12} Btu)
Gas	6,734.5	(6,381.2)
Residual oil	1,861.0	(1,762.3)
Distillate oil	1,192.9	(1,129.6)
Coal	1,163.3	(1,101.6)
Total	10,951.7	(10,374.7)

TABLE 2-19. ESTIMATED FUEL CONSUMPTION BY INDUSTRIAL AND COMMERCIAL BOILERS, 1975

Sector	Consumption		
	Quantity		Heat content, 10^{15} Joules (10^{12} Btu)
Industrial			
Coal	33,906 Gg	(39,374 x 10^3 tons)	1031.0 (976.5)
Residual oil	19,881 x 10^3 m^3	(125,067 x 10^3 bbl)	830.8 (786.7)
Distillate oil	7281 x 10^3 m^3	(45,799 x 10^3 bbl)	282.0 (267.0)
Natural gas	112,237 x 10^6 m^3	(3,963,635 x 10^6 ft^3)	4282.3 (4058.8)
Total			6426.1 (6089.0)
Commercial			
Coal	4575 Gg	(5,043 x 10^3 tons)	132.1 (125.1)
Residual oil	24,657 x 10^3 m^3	(155,103 x 10^3 bbl)	1030.2 (975.6)
Distillate oil	23,521 x 10^3 m^3	(147,959 x 10^3 bbl)	910.9 (862.6)
Natural gas	64,233 x 10^6 m^3	(2,268,128 x 10^6 ft^3)	2452.5 (2322.4)
Total			4525.7 (4285.7)

A further distribution into industrial and commercial sectors shows that industrial boilers consume more fuel overall (a little over 58 percent of the total) but that commercial boilers do contribute substantially to total consumption, and that they use a considerable amount of "dirty" fuel (i.e., coal and residual oil). These data are presented in Table 2-19.

The figures for consumption of major fuels were subdivided for industrial consumption into quantities used for generation of electricity, process steam, and space heating. The distribution was based upon end-use-fuel estimates obtained from the Department of Energy survey of Major Fuel Burning Installations (MFBI), (DOE, 1975). These end-use distributions were applied to the total industrial fuel consumption figure, reported in the Mineral Industry Surveys (Bureau of Mines, 1976 a, b, c) using the procedures described in Appendix D. The results are shown in Table 2-20.

TABLE 2-20. FUEL CONSUMPTION FOR INDUSTRIAL BOILERS

	Total energy, 10^{15} J (10^{12} Btu)		
Fuel	Electric generation	Process steam	Space heat
Coal	257.8 (244)	618.6 (586)	154.6 (147)
Residual oil	108.8 (102)	606.5 (574)	115.5 (111)
Distillate oil	38.4 (36)	90.8 (86)	152.8 (145)
Natural gas	475.8 (451)	3330.6 (3157)	475.8 (451)
	880.8 (833)	4646.5 (4403)	898.7 (854)

The MFBI data, however, are less than completely satisfactory. Only boilers having a capacity over 29 MW (100 x 10^6 Btu/h) were included, and the number of boilers (3670) was limited. All the boilers in this size range are water-tube boilers, and the present study estimates that 5603 water-tube boilers have a capacity greater than 29 MW (100 x 10^6 Btu/h). Thus, the DOE survey accounted for only 65 percent of the estimated boiler population. In addition, the MFBI data contained obvious errors that invalidated some of the data and cast doubt on the validity of the remaining information.

An attempt was made to verify the percent distributions for each usage by comparing the MFBI based finding with those reported by Stanford Research Institute (Stanford, 1970). The basis for the Stanford study differed in that it combined industrial process steam and space heat into one category, and that it reported a total for petroleum products. Table 2-21 presents the results of the comparison of the two different studies.

TABLE 2-21. COMPARISON OF FUEL AND USE ESTIMATES

Fuel	Study	Electric generation	Process steam and space heat
Coal	Stanford study	3.8%	96.2%
	Present study	26.8%	71.2%
Oil	Stanford study	3.7%	96.3%
	Present study	13.4%	86.6%
Natural Gas	Stanford study	3.9%	96.1%
	Present study	11.1%	88.9%

The fuel usage estimate for generation of electricity, derived from MFBI data, is consistently higher than the usage estimated by Stanford. The Stanford study does not state how the distribution between electric generation and other industrial uses was determined, but the similarity between values for different fuels suggests that a single factor was used for all fuels.

Since the MFBI study focused on boilers over 29 MW (100 x 10^6 Btu/h), and it is this boiler capacity category that is likely to account for almost all of the electricity generation by industrial boilers, applying the MFBI fuel usage distribution to the total industrial fuel consumption creates an unrealistically high estimate for the percent of fuel being used to generate electricity. Adjusting these values to reflect fuel consumption by all types and sizes of industrial boilers should yield values between 10 and 15 percent of consumption of coal for the generation of electricity and 5 to 10 percent of consumption for gas and oil. No further attempt was made at reconciling the differences between the MFBI generated and Stanford values. There are insufficient data to permit calculation of fuel consumption by size of boiler (needed to determine actual enduse-fuel distribution), and further efforts to reconcile the values are not justified in light of the limited utility of such findings.

The estimates of fuel consumption and capacity permitted the computation of overall load factors. The results of this computation are shown in Table 2-22.

TABLE 2-22. ESTIMATED LOAD FACTORS FOR INDUSTRIAL AND COMMERCIAL BOILERS BY FUEL

Industrial fuel	Capacity, MW thermal	(10^6 Btu/h)	Consumption, 10^{15} J	(10^{12} Btu)	Calculated load factor
Coal	181,601	(619,800)	1,031.2	(976.5)	0.180
Residual oil	248,464	(848,000)	830.8	(786.7)	0.106
Distillate oil	66,277	(226,200)	282.0	(267.0)	0.135
Gas	433,406	(1,479,200)	4,282.0	(4,058.8)	0.313
Commercial fuel					
Coal	57,926	(197,700)	132.1	(125.2)	0.072
Residual oil	110,783	(378,100)	1,030.2	(975.6)	0.295
Distillate oil	61,471	(209,800)	910.9	(862.6)	0.469
Gas	169,090	(577,100)	2,452.5	(2,322.4)	0.459
Total	1,329,019	(4,535,900)	10,951.7	(10,374.7)	0.261

The figures in some categories are low compared with previous estimates, and the weighted average of 26.1 percent is lower than the estimate of 35 percent from a previous boiler study (Ehrenfeld et al., 1971). Estimates from Battelle (Putnam et al., 1974) are in Table 2-23 with the comparable value from the present study.

TABLE 2-23. COMPARISON OF BATTELLE AND PEDCO LOAD FACTORS

	Estimated load factors by fuel			
	Commercial		Industrial	
	Battelle	PEDCo	Battelle	PEDCo
Pulverized coal and cyclone	0.424	0.072	0.524	0.180
Other coal fired	0.305		0.426	
Residual oil	0.245	0.295	0.368	0.106
Distillate oil	0.206	0.469	0.330	0.135
Natural gas	0.318	0.459	0.518	0.313

The Battelle estimates were derived from data contained in the EPA National Emissions Data System (NEDS). These data have known limitations (e.g., New York State is not included), and contain some errors. Battelle reported, for example, that for some boilers the reported capacity and fuel consumption produced a load factor greater than 1.0. Thus the Battelle load factors, although generally considered as the best available, are not based on complete data; differences with them do not necessarily diminish the credibility of the data used to derive national average load factors for this study.

Nevertheless the values derived in this study for industrial units appear low. This is probably because of assumptions concerning replacement rates. Based upon discussions with boiler manufacturers, it was assumed that 27 percent of the sales of water-tube and fire-tube boilers and 50 percent of the sales of cast iron boilers were replacements. These assumptions directly affect the total boiler capacity calculations (e.g., 27 percent of the new capacity additions for water-tube boilers replace existing units yielding a net increase in capacity of 73 percent of the sales). Furthermore, the assumptions do not factor in replacement of coal-fired units by new oil- and gas-fired capacity (i.e., if a new oil- or gas-fired unit is purchased to replace a coal-fired unit, no corresponding reduction in the coal-fired capacity was incorporated in the study). The sales data for water-tube and fire-tube boilers were obtained from ABMA for 1966 through 1975, and the data on cast iron boilers were obtained from the Hydronics Institute for 1965 through 1975. Sales of coal-fired boilers were quite low for the period covered; hence, the assumed retirement rate was also low. The average boiler age data presented in Table 2-24 suggest that the assumption led to overestimates of existing coal-fired boilers, since the percent of new capacity for coal-fired units is much lower than for other fuels.

On the other hand, the figures may indicate that a substantial number of boilers are on standby. The relatively low load factors for boilers firing residual oil may be explained in the same manner, since sales of water-tube boilers (which are by far the largest class) were low in relation to the total number of water-tube boilers. The low load factor for boilers firing distillate oil in industrial service and the high load factor for those in commercial service suggest that some assumptions made about type of service may be invalid. The load factors for gas are not unreasonable, except that the factor for industrial service was expected to be higher than that for commercial service. The use of interruptible gas by industrial concerns may be a partial explanation, however, or the ratios presented by Battelle and used in this study for industrial versus commercial boilers (Putnam et al., 1974) may not be applicable to the present population of boilers.

Additional work is required to resolve the replacement, retirement, and standby issues in order to generate better estimates of capacity; the required information could probably be obtained most effectively by canvassing the boiler manufacturers and contacting the ABMA.

Although considerable effort was expended in this study to develop good estimates of capacity, the retirement and replacement issue could not be pursued further within the existing study constraints. Furthermore, the calculated load factors are not used directly in other parts of the study since emission estimates

TABLE 2-24. COMPARISON OF BOILERS BY AGE

Boiler type	Boiler capacity, MW thermal (10^6 Btu/h)		% New
	Old	New[a]	
Water-tube			
Coal	170,400 (581,600)	9,700 (33,100)	5.4
Residual oil	177,100 (604,400)	43,400 (148,100)	19.7
Distillate oil	33,000 (112,500)	5,700 (19,400)	14.7
Natural gas	220,300 (752,000)	86,100 (293,800)	28.1
Fire-tube			
Coal	26,200 (89,400)	0 (0)	0
Residual oil	52,700 (179,800)	30,700 (104,800)	36.8
Distillate oil	34,300 (117,200)	20,200 (69,000)	37.1
Natural gas	101,100 (345,100)	37,500 (127,900)	27.0
Cast iron			
Coal	30,500 (104,200)	1,100 (3,600)	3.3
Residual oil	30,500 (104,100)	23,300 (79,500)	43.3
Distillate oil	19,600 (66,800)	14,300 (48,700)	42.2
Natural gas	100,500 (343,000)	43,000 (146,800)	30.0
All boilers			
Coal	227,100 (775,200)	10,800 (36,700)	4.5
Residual oil	260,300 (888,300)	97,400 (332,300)	27.2
Distillate oil	86,900 (296,500)	40,200 (137,100)	31.6
Natural gas	421,900 (1,440,100)	166,600 (568,500)	28.3

[a] New represents capacity added between the years 1967 and 1977.

are based on fuel consumption statistics, and further analysis of trends of the past 10 years would not necessarily provide additional insight on current and future practice.

2.4 GROWTH PROJECTIONS FOR INDUSTRIAL/COMMERCIAL BOILER POPULATION

The major factors affecting the future growth of the industrial/commercial boiler population are the economic growth of the Nation, technological advancements in energy production and use, fuel use patterns, and energy and environmental regulatory trends. Although the projections contained in this section are based only on economic growth, the qualitative effect of the other factors will be discussed.

In the industrialized states, State Implementation Plan (SIP) requirements for fossil-fuel-fired boilers include regulations governing emissions of particulate matter and sulfur dioxide (SO_2) from industrial boilers. A typical equation based on the Illinois SIP for allowable particulate emissions is:

$$E = 5.18\ Q^{-0.715}$$

where E is allowable particulate emissions in $lb/10^6$ Btu

Q is heat input rate in 10^6 Btu/h.

The allowable particulate emission rate ranges from 430 to 43 ng/J (1.0 to 0.1 $lb/10^6$ Btu) as the heat input varies from 2.3 to 73.25 MW thermal (10 to 250 x 10^6 Btu/h).

Regulations governing SO_2 emissions vary for each type of fuel. For coal firing, SO_2 regulations vary from 86 to 2580 ng/J (0.2 to 6.0 $lb/10^6$ Btu). For fuel oil firing, the regulations (normally expressed as a limitation on the sulfur content in the fuel) are equivalent to 86 to 344 ng/J (0.2 to 0.8 $lb/10^6$ Btu).

To date no Federal regulations have been promulgated for new boiler installations under 73.3 MW thermal (250 x 10^6 Btu/h) heat input, and manufacturers of industrial boilers have not yet had to deal extensively with emission limitation problems. The relative distribution of boiler types (package versus field-erected) could change dramatically, however, in response to Federally mandated regulations.

In addition to being affected by environmental regulations, new boilers with a heat input greater than 29.3 MW thermal (100 x 10^6 Btu/h) will be subject to the DOE coal conversion strategy for new boilers. This DOE strategy seeks to restrict the use of natural gas and oil by prohibiting the burning of fuels other than coal, coal-derived liquids, and refuse-derived fuels without prior DOE critical review and approval. Obviously, mandatory coal firing will change the distribution of fuels fired in large industrial boilers by the year 2000; however, near-term DOE policies (i.e., up to 1980 or 1981) are emphasizing the burning of more natural gas at the expense of oil.

Technological advancements such as fluidized-bed combustion also may increase the coal usage as cleaner, more efficient, firing processes are developed. New sources of energy and advances in energy conservation also will influence boiler growth rate and fuel usage patterns. The scope of this study, however, does not address the quantitative effects of these factors.

Because of the uncertainties, boiler manufacturers are unwilling to predict growth trends in the industrial boiler population. The Institute of Gas Technology (IGT) made some projections in 1974 of economic growth and boiler fuel distributions, however, and these were utilized to derive the results presented in this section. It should be noted that projected growth rate for the industrial boilers is based on growth in energy consumption, assuming no shift in load factors; the growth rate for commercial boilers is assumed to parallel that of industrial boilers.

The IGT study (Fejer and Larson, 1974) considers the growth of the five most energy-intensive industries in the United States:

Paper and allied products	SIC 26
Chemical products	SIC 28
Petroleum refining	SIC 29
Mineral products	SIC 32
Primary metals	SIC 33

Based on 1971 production for these industries and assumptions concerning anticipated future market demands, IGT projected the production of these industries for 1975, 1980, and 1985. Using the 1971 energy use for steam production per unit of output as a base, IGT calculated the 1975, 1980, and 1985 energy use for each of the industries except petroleum refining; energy usage in petroleum refining is not easily related to production.

Table 2-25 presents projections of energy usage for producing steam for the four key industries through 1985. These projections were derived from the IGT data based on two important assumptions:

- The relative proportion of energy used for producing steam will remain constant through the projection period.
- The amount of energy consumed per unit of production will remain constant (i.e., new technologies with different efficiencies are not considered).

A composite industrial annual growth rate of 3.3 percent was derived from the data in Table 2-25 for the period 1975 through 1985, and this growth rate was assumed to continue from 1985 to 2000.

Based on the report by the Stanford Research Institute (1972), the total energy used by the four key industries for process steam accounted for approximately 82 percent of the total process steam energy used by all industries in 1971. Furthermore, it was assumed that total energy consumption for process steam by the four key industries will continue to be 82 percent of the total energy consumed industrywide for process steam. Therefore, the growth rate of energy consumption for process steam by the four key industries from 1971 to 1985 was assumed to be representative of the growth rate of energy consumption for process steam by all industries.

TABLE 2-25. PROJECTED TOTAL ENERGY USAGE BY THE FOUR MAJOR ENERGY-INTENSIVE INDUSTRIES
[10^{15} J (10^{12} Btu)]

Industry	1971[a]	1975	1980	1985
Paper and allied products	1,284 (1,218)	1,537 (1,459)	1,766 (1,675)	2,018 (1,914)
Chemical products	3,969 (3,764)	4,824 (4,575)	587 (5,569)	6,936 (6,484)
Mineral products	724 (687)	802 (761)	879 (834)	948 (899)
Primary metals	4,074 (3,864)	4,884 (4,632)	5,894 (5,590)	6,921 (6,564)
Total	10,051 (9,533)	12,047 (11,426)	14,411 (13,668)	16,723 (15,861)

[a] Actual reported energy usage.

Given these assumptions, industrywide energy consumption for process steam in the year 2000 can be calculated by dividing the energy consumption for process steam by the four key industries by 0.82.

The growth in energy use for production of steam of all industries (presented in Figure 2-2) was calculated in this manner.

The growth rate for capacity of industrial and commercial boilers is assumed to equal the energy growth rate. Therefore, the projected emissions shown later in Section 3.3 are based on the application of the energy growth rate (i.e., 3.3% per year) to the actual 1975 fuel consumption data derived in Section 2.3. Table 2-26 presents a summary of the capacity of industrial and commercial boilers in place in 1977 by fuel type. These totals and the projected growth factor determined earlier form the basis for calculating the total capacity of industrial/commercial boilers for 1980, 1985, and 2000 (Table 2-27). The calculations required the following additional assumptions:

- The relationship between boiler capacities and total energy consumed (i.e., the load factor) will remain constant over the projected period.
- The energy use projection factor of 1.033 can be applied to total boiler capacity.

Data from other studies by Edison Electric Institute (1976) and the Energy Information Administration (1977) can be used to check the reasonableness of the 3.3 percent growth rate.

The well-researched book written by the Edison Electric Institute (1976) analyzes the growth of energy use as it relates to economic growth. Several scenarios were developed representing interactions of nine separate elements: (1) population, (2) agriculture, (3) growth of income and consumption, (4) minerals demand and supply, (5) energy demand and supply, (6) conservation and environment, (7) pricing policies, (8) capital requirements, and (9) relations with the rest of the world. By varying some of these elements, EEI formulated three scenarios of energy demand

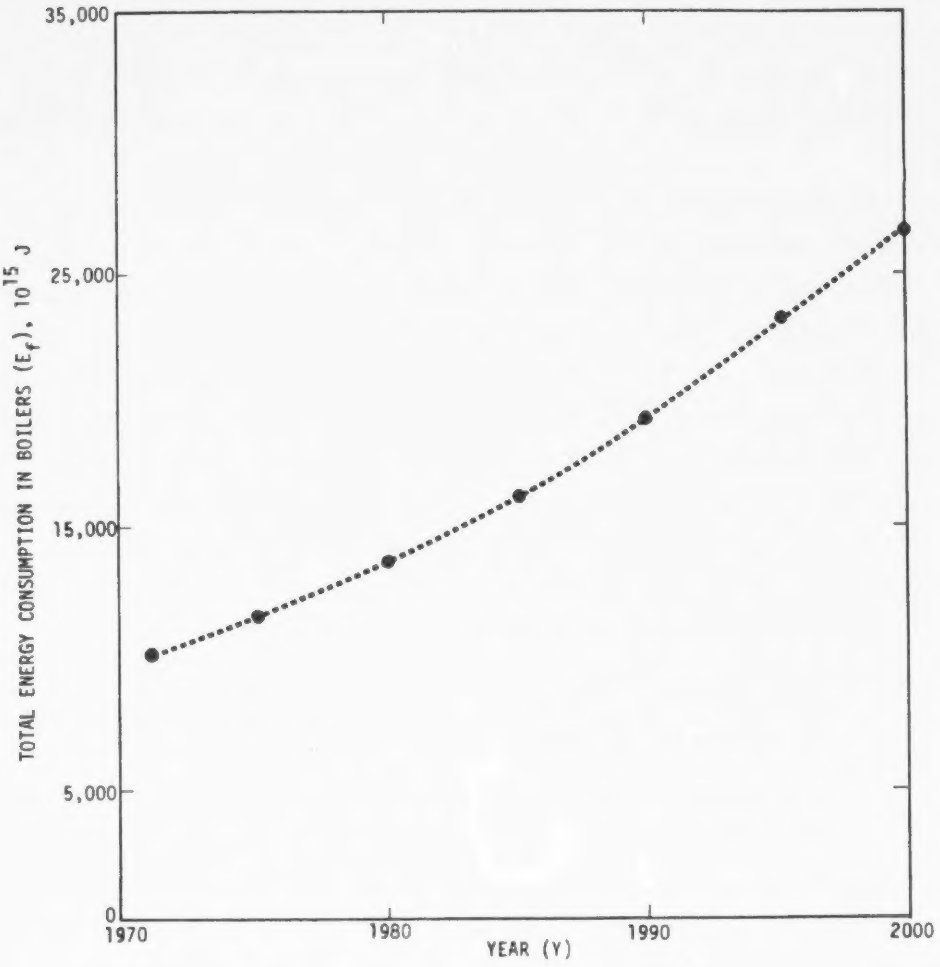

Figure 2-2. Projected growth in energy use by boilers through 2000.

TABLE 2-26. TOTAL U.S. CAPACITY OF INDUSTRIAL/COMMERCIAL BOILERS BY FUEL TYPE IN 1977

Fuel type	1977 Capacity, MW thermal (10^6 Btu/h)	% of total
Stoker coal	178,450 (608,850)	13.6
Pulverized coal	60,690 (207,100)	4.6
Residual oil	358,570 (1,223,800)	27.3
Distillate oil	127,040 (433,700)	9.7
Natural gas	588,590 (2,008,800)	44.8
Total	1,313,340 (4,482,230)	100

TABLE 2-27. PROJECTED TOTAL CAPACITY OF U.S. INDUSTRIAL/COMMERCIAL BOILERS BY FUEL TYPE

[MW thermal (10^6 Btu/h)]

Fuel type	Year		
	1980	1985	2000
Stoker coal	195,192 (665,947)	229,044 (781,446)	373,236 (1,273,394)
Pulverized coal	66,383 (226,530)	77,897 (265,817)	126,936 (433,159)
Residual oil	392,210 (1,338,611)	460,232 (1,570,772)	749,964 (2,559,629)
Distillate oil	138,959 (474,388)	163,058 (556,663)	265,709 (907,106)
Natural gas	643,809 (2,197,256)	755,467 (2,578,335)	1,231,061 (4,201,490)
Total	1,436,553 (4,902,732)	1,685,698 (5,753,033)	2,746,906 (9,374,778)

growth: Case A - high economic growth; Case B - moderate economic growth; Case C - low (or no) economic growth. Case A is predicted to result in a 4.0 percent annual increase in U.S. energy demand by the industrial sector to the year 2000; Case B is predicted to result in a 3 percent annual increase; and Case C is predicted to result in only a 0.5 percent annual increase. The EEI projections are for total energy demand by the economic sector, whereas the projections prepared in this report represent only energy used in the industrial sector for process steam production (i.e., boilers). According to DOE (1978) information on major fuel burning installations, process steam characteristically represents about 70 percent of total energy use in the industrial sector. Given this ratio, PEDCo adjusted the IGT projections for total steam energy demand to obtain an estimate of projected total industrial energy demand on the assumption that the rates remain constant. Table 2-28 presents the EEI (1976) estimates and the adjusted IGT projections. The table shows that the PEDCo and EEI predictions for the year 2000 differ by about 12 percent; most of this difference is attributable to the fact that the EEI estimate of total energy demand by the industrial sector in 1975 is 19 percent higher than the PEDCo estimate for 1975.

The study prepared for the Energy Information Administration in 1978 contains estimates for six basic scenarios of six conditions of energy supply and demand and are represented by the matrix shown in Figure 2-3.

The EIA (1978) growth factors range from 3.8 to 4.6 percent for the 1975 to 1985 period. To approximate most nearly the estimates derived from the IGT work, Scenario E (3.8 percent growth) was chosen from the EIA study. This most conservative EIA estimate for growth assumes low demand and low supply conditions. The 1985 to 1990 growth factor for Scenario E is 2.7 percent. If this factor is applied for the period 1985 to 2000, the effective growth factor for the entire 25-year period (1975 to 2000) is 3.2 percent. As shown in Table 2-28, by the year

TABLE 2-28. INDUSTRIAL ENERGY DEMANDS FROM 1975 TO 2000
[10^{15} J (10^{12} Btu)]

	Demand for process steam		Total energy demand by industrial sector		
	Four SIC's	Total	PEDCo estimate, adjusted from IGT	EEI estimate, Case A	EIA estimate, Case E
1975	12,047 (11,426)	14,691 (13,934)	20,988 (19,906)	26,010 (24,669)	21,380 (20,278)
1980	14,411 (13,668)	17,574 (16,668)	24,628 (23,359)	30,720 (29,136)	25,810 (24,480)
1985	16,723 (15,861)	20,394 (19,343)	28,980 (27,487)	35,587 (33,753)	31,156 (29,550)[a]
2000	28,840 (27,353)	35,170 (33,357)	45,570 (43,220)	51,876 (49,202)	46,989 (44,567)[b]

[a] Assumed annual growth factor from 1975 to 1985 of 3.84%.

[b] Assumed annual growth factor from 1985 to 2000 of 2.7%.

		Energy demand		
		High	Medium	Low
Energy Supply	High	A		B
	Medium		C	
	Low	D		E

Case F = High Import Prices

Figure 2-3. The EIA scenarios for energy demand projections.

2000 the projections based on EIA data are within 3 percent of those derived from the IGT data.

Although this study does not take into account the changes in fuel mix that may accompany boiler growth, the EIA (1978) and EEI (1976) studies project changes in fuel patterns expected in the United States over the next 25 years. The EIA report projects coal usage to increase at an annual rate of 1.9 to 4.6 percent between 1975 and 1985 and residual oil usage at an annual rate of 6.7 to 8.8 percent. Natural gas consumption is predicted to decrease by 0.3 percent for the same period. The EIA projections for the period 1985 to 1990 show natural gas usage increasing 2.8 percent annually; coal, 0.9 percent; and residual oil, 3.2 percent.

According to EEI (1976), the use of all fuels will increase by about 3.5 to 4.5 percent between 1975 and 1985, except coal usage, which will decrease. The period 1985 to 2000 shows increases in the usage of all fuels, with electricity and synthetic gas accounting for about 21.2 percent of the consumption in 2000.

Neither study (EEI, 1974; EIA, 1978) addresses the influence that the DOE strategy for conversion to coal firing will have on industrial fuel consumption over the next two decades. This and other strategies to conserve the Nation's oil and natural gas will undoubtedly change fuel-use distribution, especially between 1985 and 2000.

A more accurate and reliable prediction of the growth of industrial boiler capacity than that provided in this study would require a clearer definition of the extent of boiler emission regulations and their enforcement, and the effects of a full-scale coal-conversion strategy regarding new construction. Extensive use of coal will undoubtedly place new burdens and responsibilities on related coal mining and transportation activities. Anticipated mining and delivery problems related to coal supply and the effects of these problems on pricing must be considered.

Although the projected growth in total boiler capacity has been determined, no firm data are available for estimating the changes in the mix of boiler types that may occur.

To evaluate the capability of manufacturers to meet projected demand for boiler capacity, the average annual growth rates in capacity were calculated from sales data. For the period 1969 to 1975, the sales of water-tube boilers grew at an average annual rate of 3.2 percent. Fire-tube boiler sales from 1966 through 1975 grew at an annual average rate of 2.4 percent. The growth rate of cast iron boilers was calculated to be about 1.7 percent for the 1965 through 1975 period.

The 3.3 percent annual average growth rate would correspond with the growth in fuel consumption, not necessarily with boiler capacity. Comparison of the sales growth rates with the projected annual growth of 3.3 percent indicates that to meet this demand would require greater utilization of existing boilers. The previous assumption that load factors will remain constant is not correct and, in fact, load factors must increase in the future. The average load factor for existing boilers of 26.1 percent as calculated in Section 2.3 is very low, and it is not unreasonable to expect greater utilization under conditions of high demand. The low growth rate in cast iron boiler capacity would indicate that the use of cast iron boilers will not grow at the same rate as water-tube and fire-tube boilers, and therefore the emissions as represented in Section 3.3 will be overstated for cast iron boilers. The total emissions as presented are correct, with water-tube and fire-tube boilers accounting for a greater share.

The same uncertainties related to projecting fuel mix make it equally difficult to project quantitative changes in the mix of boiler types. Therefore the emission projections shown later in Section 3.3 are based on the present mix of boiler types.

To provide comparative figures for other rates of economic growth, emission projections for the EIA high growth case (4.6 percent annual growth rate) and for the EEI low growth case (0.5

percent annual growth rate) are also given in Section 3.3. For these two cases, the same assumptions are made regarding no change in fuel mix or the distribution in boiler types through the year 2000.

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SECTION 3

ATMOSPHERIC EMISSIONS

The burning of fuel in boilers causes emissions of significant quantities of particulate matter, sulfur dioxide (SO_2), and nitrogen oxides (NO_x). Relatively minor amounts of carbon monoxide (CO), and hydrocarbons (HC) are also emitted. The following sections deal with factors affecting the emission rates, the estimated total quantity of each pollutant emitted from the 1975 boiler population, and projections of emissions through the year 2000.

3.1 EMISSION FACTORS

Exclusive use was made of the emission factors published in EPA's "Compilation of Air Pollutant Emission Factors" (U.S. EPA, 1977), hereafter referred to as "AP-42 emission factors." These factors represent averages of emissions test data. Depending upon the confidence in the amount and validity of data used in developing the emission factors, EPA has ranked each set of emission factors. The factors for boilers have been assigned the best ranking, indicating good confidence in the data. The following subsections describe variables that can affect the emissions from an individual boiler.

3.1.1 Particulate Emissions

Ranges of Particulate Emission Factors--

Tables 3-1 through 3-3 present the AP-42 particulate emission factors for industrial and commercial/institutional boilers by fuel. The emission factors for coal are listed by firing mechanism for various types and sizes of boilers. The factors are expressed in kilograms of particulate matter emitted per

TABLE 3-1. UNCONTROLLED PARTICULATE EMISSION FACTORS FOR VARIOUS COAL-FIRED BOILERS[a]

Boiler input capacity, t MW thermal (10^6 Btu/h)	Emission factor, g/kg coal burned (lb/ton coal burned)[a]					
	Pulverized			Stoker		
	Wet bottom	Dry bottom	Other	Spreader	Underfeed	Other
>29.3(>100)	6.5[b] (13[b])	8.5[b] (17[b])	8[b] (16[b])	c	c	c
2.9 - 29.3 (10 - 100)	c	c	c	6.5[b] (13[b])	c	2.5[b] (5[b])
< 2.9 (< 10)	c	c	c	c	1[b] (2[b])	c

[a] U.S. EPA, 1977.

[b] The weight percentage of ash in the coal should be multiplied by the factor given.

[c] No emission factor given in AP-42.

TABLE 3-2. UNCONTROLLED PARTICULATE EMISSION FACTORS FOR VARIOUS OIL-FIRED BOILERS[a]

oiler input capacity, MW thermal (10^6 Btu/h)	Emission factor, kg/10^3 liters oil burned (lb/10^3 gal oil burned)	
	Residual oil	Distillate oil
.7 - 63 15 - 250)	1.25 $(S)^b$ + 0.38 [10 (S) + 3]	c
3 - 3.7 0.5 - 15)	c	0.25 (2)

U.S. EPA, 1977.

S is the sulfur content of the fuel in percentage.

No emission factor given in AP-42.

TABLE 3-3. UNCONTROLLED PARTICULATE EMISSION FACTORS FOR VARIOUS NATURAL GAS-FIRED BOILERS[a]

Boiler input capacity, MW thermal (10^6 Btu/h)	Emission factor, kg/10^6 m^3 gas burned ($lb/10^6$ ft^3 gas burned)	
	Industrial	Domestic and commercial
All	80 - 240 (5 - 15)	80 - 240 (5 - 15)

[a] U.S. EPA, 1977.

kilogram of ash in the coal; therefore, given a specific coal heating value and percent ash content, it is possible to calculate the uncontrolled particulate emissions for a specific size and type of industrial boiler.

Particulate emission factors for the firing of residual oil are given by capacity ranges versus boiler firing mechanism. The emissions generated by residual oil firing are correlated with the sulfur content of the oil and are expressed as a function of sulfur content.

Particulate emission factors for the firing of distillate oil are also given by capacity ranges versus boiler firing mechanism. Because the emissions generated by distillate oil firing do not necessarily correlate with the ash content of the oil, emission factors are expressed simply as kilograms of particulate matter per joule fired (pounds particulate per million Btu fired). The emission factors for industrial boilers firing natural gas are also given in this manner.

Factors Influencing Particulate Emissions--

Coal--Particulate emissions from coal-fired boilers may consist of unburned carbon, condensable tars, and fly ash. The first two relate to the volatile content of the coal, whereas the last depends on the ash content.

Generally, pulverized-coal-fired units produce more particulate matter than coal-fired stokers, which in turn produce more than coal-fired cyclone boilers. Because coal is blown into a pulverized-coal unit, combustion occurs while the coal particles are in suspension. As it burns, the particle becomes smaller and thus is more likely to be exhausted with the flue gas. Because coal is placed on a bed in a stoker furnace, particles are less likely to be exhausted with the flue gas. Emissions of particulate matter are lowest from a cyclone furnace because most of the fly ash is collected on the walls of the boiler, which are coated with molten slag (Cato et al., 1974).

Low loads can cause emission problems in pulverized-coal-fired units. Lower furnace temperatures cause poor combustion, which leads to high emissions of particulate matter containing unburned carbon. Conversely, efficient combustion reduces the unburned carbon portion of particulate emissions. Complete combustion requires adequate oxygen, complete mixing, and a temperature above the ignition point of the fuel.

Oil--Distillate and residual oil are the primary types of fuel oil fired in industrial boilers. Distillate oil is normally fired in smaller units, and residual oil in the larger, more complicated, industrial units.

Fuel oil properties such as API gravity, carbon residue, ash content, viscosity, and volatility are important in determining particulate emissions from oil-fired units; these properties influence atomization and vaporization, which contribute to proper combustion.

Proper oil atomization is necessary to achieve complete, smoke-free combustion of oil. The quantity of emitted particulate matter is directly dependent on the size of the oil droplets, which is a function of burner type or atomization method. Incomplete vaporization of large oil droplets contributes to particulate emissions.

The current AP-42 particulate emission factor for firing of No. 6 residual oil is based on sulfur content. The theory reflected is that the sulfur level of the oil affects SO_3 adsorption; thus, greater particulate formation occurs with higher sulfur oils.

Particulate emissions from residual oil firing decrease as boiler size increases, probably because of better combustion control and an increased level of maintenance. The size-emission relationship is not so pronounced with distillate-oil-fired units; burner type appears to be the predominant design parameter affecting particulate emissions from these boilers (Offen et al., 1976).

Operating parameters affecting particulate emissions are boiler load, cycling, and maintenance. According to AP-42, for units firing No. 6 residual oil, particulate matter emissions per unit of fuel burned are lower when operating at reduced load. The effect of load reduction in distillate-oil-fired units is not as great.

Oil-fired boilers and furnaces used for space heating are often operated cyclically, i.e., with on-off cycling. This type of operation results in high particulate emission levels at startup because cold combustion chamber walls cause incomplete combustion.

Operating at high temperature and high oxygen levels may reduce particulate emissions, but it will increase NO_x emissions. Some balanced or optimized level of operation may be necessary (Offen et al., 1976).

Gas--Coke particles or soot, which result from incomplete combustion, are rarely a problem in gas-fired units (Cato et al., 1974).

3.1.2 Sulfur Oxides Emissions

Emissions of sulfur oxides (SO_x) are predominantly in the form of sulfur dioxide (SO_2), although sulfur trioxide (SO_3) can also be emitted. The emissions are often reported as SO_x to encompass both pollutants, even though the SO_3 may constitute only 1 or 2 percent of the total (U.S. EPA, 1977). SO_x emissions are highly dependent on the sulfur content of the fuel. Thus, firing of fuels with low sulfur content reduces the quantity of SO_x emissions at a given firing rate. Boiler type, firing mechanism, and mode of operation have little, if any, effect on SO_x emissions.

Ranges of SO_x Emission Factors--

Tables 3-4 and 3-5 present SO_x emission factors from AP-42 for firing of coal, residual oil, and distillate oil in various boiler sizes. Because natural-gas-fired units generate negligible amounts of SO_x, data on emissions from these boilers, given in

TABLE 3-4. UNCONTROLLED SO_2 EMISSION FACTORS FOR VARIOUS COAL-FIRED BOILERS

Boiler input capacity, MW thermal (10^6 Btu/h)	Emission factor, g/kg coal burned (lb/ton coal burned)					
	Pulverized			Stoker		
	Wet bottom	Dry bottom	Other	Spreader	Underfeed	Other
>29.3 (> 100)	19S[b] (38S)	19S (38S)	19S (38S)	c	c	c
2.9 - 29.3 (10 - 100)	c	c	c	19S (38S)	c	c
22.9 (< 10)	c	c	c	c	19S (38S)	c

[a] U.S. EPA, 1977.

[b] S is the sulfur content of the fuel in percentage.

[c] No emission factor given in AP-42.

TABLE 3-5. UNCONTROLLED SO_x EMISSION FACTORS FOR VARIOUS OIL-FIRED BOILERS[a]

Boiler input capacity, MW thermal (10^6 Btu/h)	Emission factor, kg/10^3 liters oil burned (lb/10^3 gal oil burned)	
	Industrial and commercial	
	Residual	Distillate
3.7 - 63 (15 - 250)	19.25S[b] (159S)	c
0.13 - 3.7 (0.5 - 15)	c	17.25S[b] (144S)

[a] U.S. EPA, 1977.

[b] S is the sulfur content of the fuel in percentage.

[c] No emission factor given in AP-42.

Table 3-6, are very limited. The SO_x emission factors in Table 3-4 are given as a function of coal-firing mechanism, and those in Table 3-5 as a function of types of oil. Although the data show that SO_x emissions depend almost entirely upon the sulfur content of the fuel, other considerations also may affect the total SO_x emissions from coal-fired units.

Factors Influencing SO_x Emissions--

Coal--According to AP-42, 5 percent of the sulfur available in coal is emitted with particulate matter or enters the bottom ash or slag. Because particulate emissions and ash formation depend on the firing mechanism, the SO_x emissions would also depend on the firing mechanism. Such effects are believed to be minor.

It is also postulated that SO_x emissions are affected by the form in which the sulfur occurs in the coal as well as the alkalinity of the ash. High-sulfur coals may contain inorganic sulfate, which contributes to the total sulfur content of the fuel but is not converted to SO_x gas. This inorganic sulfate could, however, add to particulate emissions (Cato et al., 1974). Highly alkaline ash can react with SO_x and cause a small amount to be removed with the fly ash.

Oil--The SO_x emissions from oil-fired units, like those from coal-fired units, are chiefly dependent on sulfur content. According to AP-42, the boiler size, grade of fuel oil, and burner design/atomization method do not affect SO_x emissions.

Natural Gas--Because natural gas contains no sulfur, there should be no SO_x emissions. As stated in AP-42, however, the chemicals that are added to natural gas for detection purposes do contain sulfur. Thus, small amounts of SO_x are emitted from natural-gas-fired units.

3.1.3 Nitrogen Oxides Emissions

Much recent research has focused on emissions of NO_x from boilers. Nitrogen oxides are mainly nitric oxide (NO) and

TABLE 3-6. UNCONTROLLED SO_2 EMISSION FACTORS FOR VARIOUS NATURAL-GAS-FIRED BOILERS[a]

Boiler input capacity, MW thermal (10^6 Btu/h)	Emission factor, kg/10^6 m^3 gas burned, (lb/10^6 ft^3 burned)	
	Industrial	Domestic and commercial
All	9.6 (0.6)	9.6 (0.6)

[a] U.S. EPA, 1977.

nitrogen dioxide (NO_2). Of a total NO_x measurement, more than 90 percent is usually NO; when it is emitted to the atmosphere, most NO eventually becomes NO_2.

Two mechanisms contribute to NO_x emissions. Atmospheric nitrogen in the combustion air combines with oxygen at the high flame temperatures attained in boilers. Nitrogen oxides produced by this mechanism are called thermal NO_x. The portion of the total NO_x that is formed from the nitrogen in the fuel is called fuel NO_x.

Ranges of NO_x Emission Factors--

Tables 3-7 through 3-9 show NO_x emission factors for firing of boilers with coal, oil, and natural gas. The data are presented by boiler capacity ranges versus firing mechanisms.

Factors Influencing NO_x Emissions--

Formation of fuel NO_x is affected primarily by the nitrogen content of the fuel and the availability of oxygen. Burning mechanisms also indirectly influence the formation of fuel NO_x. Formation of thermal NO_x is influenced by operating parameters, e.g., flame temperature, firing rate, and excess air.

The highest emissions of NO_x are from coal-fired boilers, apparently because of the nitrogen content of the fuel. With few exceptions, fuel NO_x is also the major contributor to total NO_x emissions from residual-oil-fired boilers. Fuel NO_x plays only a minor role in emissions from units fired by distillate oil and natural gas because the nitrogen content of these fuels is low.

Formation of thermal NO_x depends chiefly on temperature and oxygen concentration. These depend, in turn, upon such items as combustion air temperature, flue gas recirculation, heat release rate, excess air, and the air-to-fuel ratio. The effects of these elements are fairly consistent with all types of boilers and fuels.

Heating the combustion air increases flame temperature and enhances formation of thermal NO_x. Flue gas recirculation has the opposite effect.

TABLE 3-7. UNCONTROLLED NO_x EMISSION FACTORS FOR VARIOUS COAL-FIRED BOILERS[a]

Boiler input capacity, MW thermal (10^6 Btu/h)	Emission factor, g/kg coal burned (lb/ton coal burned)[a]					
	Pulverized			Stoker		
	Wet bottom	Dry bottom	Other	Spreader	Underfeed	Other
> 29.3 (> 100)	9 (18)	15 (30)	9 (18)	b	b	
2.9 - 29.3 (10 - 100)	b	b	b	7.5 (15)	b	b
< 2.9 (< 10)	b	b	b	b	3 (6)	b

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[a] U.S. EPA, 1977.

[b] No emission factor given in AP-42.

TABLE 3-8. UNCONTROLLED NO_x EMISSION FACTORS FOR VARIOUS OIL-FIRED BOILERS[a]

Boiler input capacity, MW thermal (10^6 Btu/h)	Emission factor, kg/10^3 liters oil burned (lb/10^3 gal oil burned)	
	Industrial and commercial	
	Residual	Distillate
3.7 - 63 (15 - 250)	7.5 (60)	b
0.13 - 3.7 (0.5 - 15)	b	2.8 (22)

[a] U.S. EPA, 1977.

[b] No emission factor given in AP-42.

TABLE 3-9. UNCONTROLLED NO_x EMISSION FACTORS FOR VARIOUS NATURAL GAS-FIRED BOILERS[a]

Boiler input capacity, MW thermal (10^6 Btu/h)	Emission factor, kg/10^6 m^3 gas burned (lb/10^6 ft^3 gas burned)	
	Industrial	Commercial
< 29.3 (< 100)	1920 - 3680 (120 - 230)	1920 (120)
> 29.3 (> 100)	11,200 (700)	b

[a] U.S. EPA, 1977.

[b] No emission factor given in AP-42.

Excess air seemingly plays a dual role in generation of thermal NO_x. Although excess air should reduce flame temperature and thus reduce the formation of thermal NO_x, it simultaneously provides additional oxygen, which enhances NO_x formation. Increasing the oxygen concentration appears to be the dominating mechanism, because increasing the excess air increases NO_x emissions (Barrett et al., 1972).

3.1.4 Carbon Monoxide Emissions

The rate of carbon monoxide (CO) emissions from boilers is dependent upon the efficiency of the combustion of the fuel.

Ranges of Carbon Monoxide Emission Factors--

The emission factors for uncontrolled carbon monoxide from boilers firing coal, oil, and natural gas (expressed per unit of fuel burned) are presented below:

	Emission factors (EPA, 1977)	
Coal-fired boilers,	g/kg	(lb/ton)
Pulverized coal	0.5	(1)
Spreader stoker	1.0	(2)
Underfeed stoker	5.0	(10)
Other stoker	5.0	(10)
Oil-fired boilers,	kg/10^6 liters	(lb/1000 gal)
Residual oil	0.63	(5)
Distillate oil	0.63	(5)
Natural-gas-fired boilers,	kg/10^6 m^3	(lb/10^6 ft^3)
Industrial	272	(17)
Commercial	320	(20)

Factors Influencing CO Emissions--

Efficiency of combustion and boiler maintenance have a major influence on CO emissions. Because proper combustion will lower emission levels, the unit should be operated with a careful control of excess air rates, use of high combustion temperatures, and provision for intimate air-fuel contact.

Small boilers are often left unattended and are poorly maintained. Improper operation and on/off cycling of smaller boilers can increase CO emissions by several orders of magnitude.

During the off cycle, the CO emissions increase drastically as the amount of excess air is decreased (Grammer et al., 1976).

These problems are not usually encountered on larger units, because they are continuously operated and well maintained.

3.1.5 Hydrocarbon Emissions

The rate of hydrocarbon (HC) emissions from boilers is dependent upon the efficiency of the combustion of the fuel. Hydrocarbon emissions are minimal when proper combustion practices are used.

Ranges of Hydrocarbon Emission Factors--

The emission factors for uncontrolled hydrocarbons from boilers firing coal, oil, and natural gas (expressed per unit of fuel burned) are presented below:

	Emission factors (EPA, 1977)	
Coal-fired boilers,	g/kg	(lb/ton)
Pulverized coal	0.15	(0.3)
Spreader stoker	0.5	(1)
Underfeed stoker	1.5	(3)
Other stoker	1.5	(3)
Oil-fired boilers,	kg/10^3 liters	(lb/1000 gal)
Residual oil	0.12	(1)
Distillate oil	0.12	(1)
Natural-gas-fired boilers,	kg/10^6 m^3	(lb/10^6 ft^3)
Industrial	48	(3)
Commercial	128	(8)

Factors Influencing HC Emissions--

The emission of unburned combustibles, such as hydrocarbons, is influenced by the efficiency of combustion and the condition of the boiler. Careful control of excess air rates, use of high combustion temperatures, and provision of intimate fuel-air contacts (high turbulence) will minimize HC emissions.

Emissions from a particular boiler will also be affected by fuel changes. For example, a liquid or gaseous fuel may have better mixing and firing characteristics than a solid fuel. The substitution of oil or natural gas for coal should, therefore, reduce HC emissions.

3.2 CURRENT LEVELS OF UNCONTROLLED EMISSIONS

Estimates of the total quantities of particulate matter, SO_2, NO_x, CO, and HC emitted by the industrial/commercial boiler population are based on the estimated quantity of fuel burned by each segment of the population, an average analysis of these fuels, and the emission factors presented in the preceding section. Details of the emissions calculations for each pollutant are presented in Appendix F.

The estimated fuel consumption figures presented in Section 2.3 are for the entire boiler population, and actual fuel consumption by boiler type (i.e., water-tube versus fire-tube) is not known. For purposes of estimating emissions, fuel consumption is assumed to be proportional to total capacity within a given boiler type. The estimated fuel consumption for each boiler type, proportioned by capacity, is shown in Table 3-10, and these values are used throughout this section for calculation of emissions.

3.2.1 Particulate Emissions

Particulate emissions from coal-fired boilers are correlated with the ash content of the coal. To estimate emissions, average ash content of coal in the United States was calculated by weighting the average ash content of the coal consumed in each state by the quantity of coal consumed by boilers in that state. Ash content values were obtained from data published by the Federal Power Commission (FPC, 1976).

Particulate emissions from residual-oil-fired boilers are correlated with the sulfur content of the oil. The average sulfur content of residual oil in the United States was calculated by weighting the average sulfur content of residual oil consumed in each state by the quantity of residual oil consumed

TABLE 3-10. ESTIMATED DISTRIBUTION OF FUEL CONSUMPTION BY BOILER TYPE FOR 1975

Boiler type	Consumption by fuel/firing						
	Pulverized coal, Gg/yr (10^3 tons/yr)	Spreader-stoker coal, Gg/yr (10^3 tons/yr)	Underfeed-stoker coal, Gg/yr (10^3 tons/yr)	Other stoker coal, Gg/yr (10^3 tons/yr)	Residual oil, m^3/yr (10^3 bbl/yr)	Distillate oil, m^3/yr (10^3 bbl/yr)	Natural gas m^3/yr (10^6 ft^3/yr)
Water-tube	10,193 (11,236)	7,979 (8,795)	9,388 (10,349)	3,022 (3,331)	658 (173,706)	227 (60,066)	85,977 (3,036,153)
Fire-tube	0	444 (489)	3,304 (3,642)	645 (711)	244 (64,439)	315 (83,316)	40,235 (1,420,618)
Cast iron	0	161 (178)	4,513 (4,975)	645 (711)	159 (42,025)	191 (50,376)	50,259 (1,774,992)

by boilers in that state. The values for sulfur content were obtained from data published by DOE (1977).

Particulate emissions from distillate oil and natural gas are correlated only with the quantity of fuel burned; fuel analyses are not needed.

Total estimated particulate emissions from the industrial/commercial boiler population (presented in Table 3-11) were calculated by applying the appropriate emission factor to the total quantity of fuel consumed in each category.

An estimated 2.5 Tg (2.8 x 10^6 tons) of uncontrolled particulate matter were emitted by boilers in 1975. Almost all of this was attributable to coal firing with about half being associated with pulverized coal and half associated with stoker coal. The average control efficiency is estimated to be 56 percent, resulting in a controlled emission amount of 1.1 Tg. Total nationwide particulate emissions in 1975 were estimated to be 14.4 Tg (EPA, 1976), thus industrial/commercial fuel consumption accounts for approximately 8 percent of nationwide total suspended particulate emissions.

3.2.2 SO_x Emissions

Sulfur oxides emissions are dependent upon the quantity of fuel consumed (Table 3-10) and the sulfur content of the fuel. Therefore, it was necessary to obtain an average sulfur content for each fuel type except natural gas. The average sulfur content of coal in the United States was calculated by weighting the average sulfur content of coal consumed in each state by the quantity of coal consumed by boilers in that state. The values for sulfur content were obtained from data published by the FPC (1976). The same procedure and data source were used to develop an average sulfur value for distillate oil as were described in Section 3.2.1 for residual oil.

The total SO_x emissions were calculated by using the appropriate emission factor from Section 3.1.2, the average sulfur content of the fuel, and the quantity of fuel listed in Table 3-10.

TABLE 3-11. ESTIMATED UNCONTROLLED EMISSIONS OF PARTICULATE MATTER FROM THE INDUSTRIAL/COMMERCIAL BOILER POPULATION FOR 1975

Boiler type	Estimated emissions by fuel, Mg/yr (tons/yr)					
	Pulverized coal	Stoker coal	Residual oil	Distillate oil	Natural gas	Total
Water-tube	1,092,300 (1,204,000)	1,084,100 (1,195,000)	59,900 (66,000)	2,300 (2,500)	13,800 (15,200)	2,252,400 (2,482,700)
Fire-tube	0	104,300 (115,000)	22,200 (24,500)	3,200 (3,500)	6,400 (7,100)	136,100 (150,100)
Cast iron	0	96,200 (106,000)	14,500 (16,000)	1,900 (2,100)	8,000 (8,900)	120,700 (133,000)
Total	1,092,300 (1,204,000)	1,284,600 (1,416,000)	96,600 (106,500)	7,400 (8,100)	28,200 (31,200)	2,509,200 (2,765,800)

The estimates for sulfur oxide emissions are shown on Table 3-12. Most of the 2.9 Tg of emissions estimated for 1975, accounting for 12 percent of the nationwide total, is divided about equally between coal and residual-oil-fired boilers. Less than 15 percent is discharged from pulverized-coal burning boilers, which are all in the size categories of 29.3 to 73.3 MW thermal (100 to 250 x 10^6 Btu/h) and larger. About 25 percent of the total is from stoker coal-fired boilers. The residual-oil-fired water-tube boilers are the largest single source of SO_x among all the boiler capacities. For this category, over 90 percent of the total capacity is represented by boilers over 7.3 MW thermal (22 x 10^6 Btu/h) and over two-thirds are between 7.3 MW thermal (25 x 10^6 Btu/h) and 29.3 MW thermal (250 x 10^6 Btu/h). It thus appears that SO_x comes mainly from small industrial and commercial boilers likely to discharge pollutants at low levels, and thus having the potential for significantly contributing to high ambient SO_2 levels.

3.2.3 NO_x Emissions

The NO_x emissions factors from AP-42 (EPA, 1977) can be applied without fuel analyses. Therefore, total NO_x emissions were calculated by applying the emission factors from Section 3.1.3 to the fuel consumption listed in Table 3-10. Results of the calculations are presented in Table 3-13. The estimated emissions of NO_x are about 1.8 Tg. This is significantly lower than the U.S. Environmental Protection Agency estimate of 4.5 Tg for NO_x from industrial boilers (EPA, 1976). The exact origin of the EPA estimate is not known.

3.2.4 CO Emissions

Carbon monoxide emissions are dependent upon boiler configuration and fuel consumption rather than fuel analysis. Total CO emissions were calculated by applying the emission factors from Section 3.1.4 to the quantity of fuel consumed by the approximate boiler type as presented in Table 3-10. Results of the calculations

TABLE 3-12. ESTIMATED UNCONTROLLED EMISSIONS OF SO_x FROM THE INDUSTRIAL/COMMERCIAL BOILER POPULATION FOR 1975

Boiler type	Estimated emissions by fuel, Mg/yr (tons/yr)					
	Pulverized coal	Stoker coal	Residual oil	Distillate oil	Natural gas	Total
Water-tube	387,000 (427,000)	775,000 (854,000)	794,500 (875,800)	38,700 (42,700)	800 (900)	1,996,000 (2,200,400)
Fire-tube	0	167,000 (184,000)	294,700 (324,900)	53,700 (59,200)	400 (400)	515,800 (568,500)
Cast iron	0	202,300 (223,000)	192,200 (211,900)	32,500 (35,800)	500 (500)	427,500 (471,200)
Total	387,000 (427,000)	1,144,300 (1,261,000)	1,281,400 (1,412,600)	124,900 (137,700)	1,700 (1,800)	2,939,300 (3,240,100)

TABLE 3-13. ESTIMATED UNCONTROLLED EMISSIONS OF NO_x FROM THE INDUSTRIAL/COMMERCIAL BOILER POPULATION FOR 1975

Boiler type	Estimated emissions by fuel, Mg/yr (tons/yr)					
	Pulverized coal	Stoker coal	Residual oil	Distillate oil	Natural gas	Total
Water-tube	91,600 (101,000)	110,700 (122,000)	198,600 (218,900)	25,200 (27,800)	962,900 (1,062,700)	1,389,000 (1,532,400)
Fire-tube	0	19,100 (21,000)	73,700 (81,200)	34,900 (38,500)	112,700 (124,300)	240,400 (265,000)
Cast iron	0	19,100 (21,000)	48,000 (53,000)	21,100 (23,300)	105,300 (116,300)	193,500 (213,600)
Total	91,600 (101,000)	148,900 (164,000)	320,300 (353,100)	81,200 (89,600)	1,180,900 (1,303,300)	1,822,900 (2,011,000)

are presented in Table 3-14. About half the total CO emissions arise from water-tube boilers. Total CO emissions, amounting to 0.2 Tg/yr, are insignificant compared to particulate matter and SO_x emissions, and were less significant when compared with the total nationwide CO emission estimate of 85.9 Tg/yr (EPA, 1976).

3.2.5 HC Emissions

Hydrocarbon emissions, like CO emissions, are dependent only on boiler configuration and fuel consumption. Total HC emissions were calculated by applying the emission factors from Section 3.1.5 to the quantity of fuel consumed by the approximate boiler type as presented in Table 3-10. Results of the calculation are presented in Table 3-15. Total HC emissions from boilers are insignificant, contributing only 0.06 Tg/yr out of a nationwide total of 26.2 Tg/yr.

3.3 EMISSION PROJECTIONS TO 2000

Based on the 1975 uncontrolled emission levels determined in Section 3.2, projected emissions from industrial and commercial boilers can be calculated by using the growth rate for these boilers as presented in Section 2.4. The weighted average annual growth rate was determined to be 3.3 percent. Projections are presented in this section for each type of boiler for particulate, SO_x, and NO_x emissions. Hydrocarbon and carbon monoxide emissions were not projected because of their insignificant contribution to nationwide totals.

3.3.1 Particulate Emissions

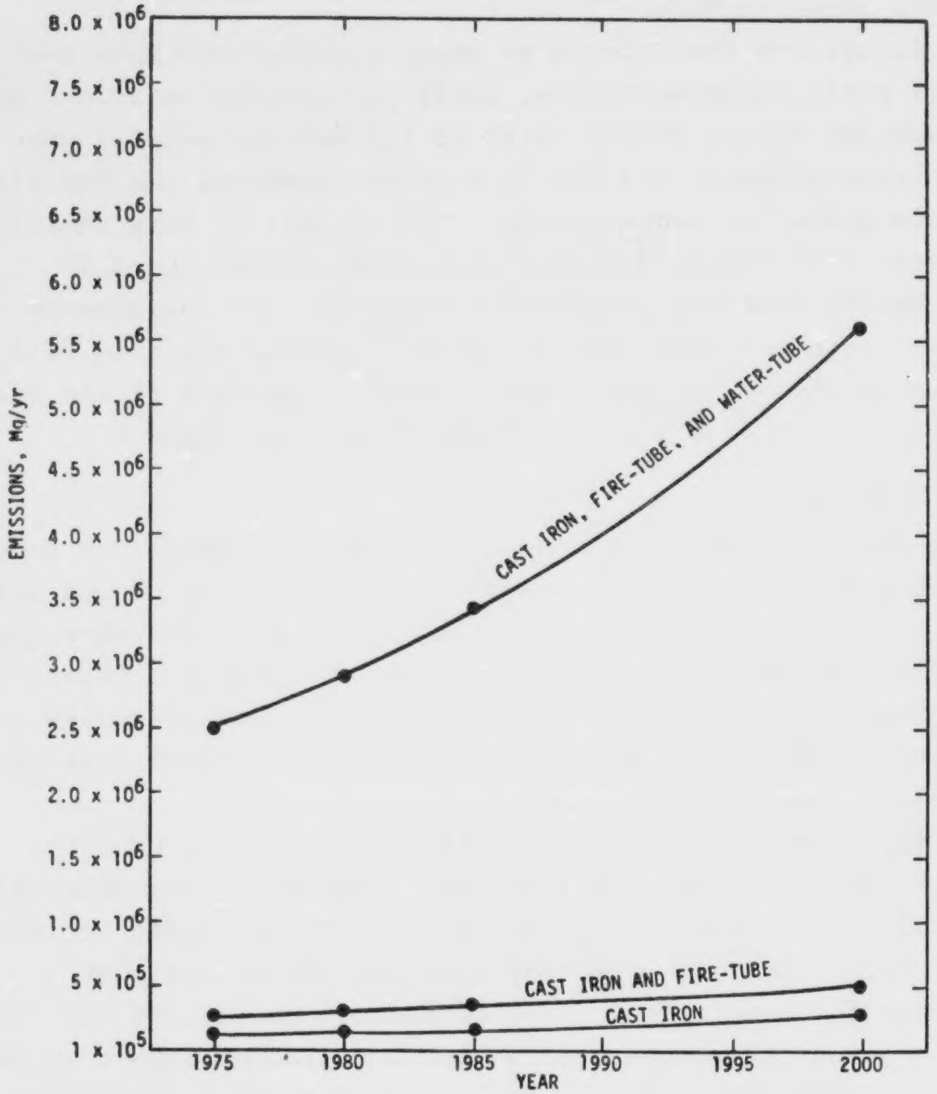
Figure 3-1 shows projected, uncontrolled emissions of particulate matter from water-tube, fire-tube, and cast iron boilers for the period 1975 to 2000 with a 3.3 percent growth rate in fuel consumption. Total particulate emissions are sensitive to the relative quantity and ash content of coal used compared with oil and natural gas. The probable increase in coal consumption

TABLE 3-14. ESTIMATED UNCONTROLLED EMISSIONS OF CO FROM THE INDUSTRIAL/COMMERCIAL BOILER POPULATION FOR 1975

Boiler type	Estimated emissions by fuel, Mg/yr (tons/yr)					
	Pulverized coal	Stoker coal	Residual oil	Distillate oil	Natural gas	Total
Water-tube	5,100 (5,600)	57,900 (63,800)	16,500 (18,200)	5,700 (6,300)	24,100 (27,300)	109,300 (121,200)
Fire-tube	0	18,400 (20,300)	6,100 (6,800)	7,900 (8,700)	12,100 (13,400)	44,500 (49,200)
Cast iron	0	23,400 (25,800)	4,000 (4,400)	4,800 (5,300)	16,100 (17,700)	48,300 (53,200)
Total	5,100 (5,600)	99,700 (109,900)	26,600 (29,400)	18,400 (20,300)	52,300 (58,400)	202,100 (223,600)

TABLE 3-15. ESTIMATED UNCONTROLLED EMISSIONS OF HC FROM THE INDUSTRIAL/COMMERCIAL BOILER POPULATION FOR 1975

	Estimated emissions by fuel, Mg/yr (tons/yr)					
Boiler type	Pulverized coal	Stoker coal	Residual oil	Distillate oil	Natural gas	Total
Water-tube	1,500 (1,700)	19,600 (21,600)	3,300 (3,600)	1,100 (1,300)	5,400 (6,000)	30,900 (34,200)
Fire-tube	0	5,700 (6,300)	1,200 (1,400)	1,600 (1,800)	3,500 (3,900)	12,000 (13,400)
Cast iron	0	7,500 (8,300)	800 (900)	1,000 (1,100)	6,400 (7,100)	15,700 (17,400)
Total	1,500 (1,700)	32,800 (37,200)	5,300 (5,900)	3,700 (4,200)	15,300 (17,000)	58,600 (66,000)



gure 3-1. Projected total uncontrolled particulate matter emissions from the industrial/commercial boiler population through 2000.

as a result of coal conversion strategies is not reflected in the emission projections presented here. As coal conversion strategies are implemented, particulate emissions will increase above the levels shown in Figure 3-1.

To illustrate the effects of other growth rates upon the amount of particulate emissions, total particulate emissions were calculated for annual growth rates of 4.6 percent and 0.5 percent, corresponding to the EEI high-growth scenario and the EIA low-growth scenario, respectively. The results of this analysis are presented in Figure 3-2 with the emissions for the 3.3 percent growth case for comparative purposes. In the absence of controls, emissions under the 3.3 percent growth scenario will more than double by the year 2000. About 80 percent of the total emissions will be from boilers in the industrial sector.

3.3.2 SO_x Emissions

Figure 3-3 shows projected uncontrolled SO_x emissions from water-tube, fire-tube, and cast iron boilers for the period 1975 to 2000. Since total SO_x emissions will change in direct proportion to changes in sulfur content of the fuels burned, total SO_x emissions will also increase somewhat beyond those projected in proportion to the replacement of natural gas and distillate oil with coal.

To illustrate the effects of other growth rates upon the amount of SO_x emissions, total SO_x emissions were also calculated for annual growth rates of 4.6 percent and 0.5 percent, and are shown in Figure 3-4 with the emissions for the 3.3 percent growth case for comparison. Coal conversion strategies will have little impact on the commercial sector and limited impact on the industrial sector because coal sulfur content is restricted by the requirement that SO_x emissions cannot increase when converting to coal.

3.3.3 NO_x Emissions

Figure 3-5 shows projected uncontrolled NO_x emissions for the period 1975 to 2000. The NO_x emissions from boilers are most

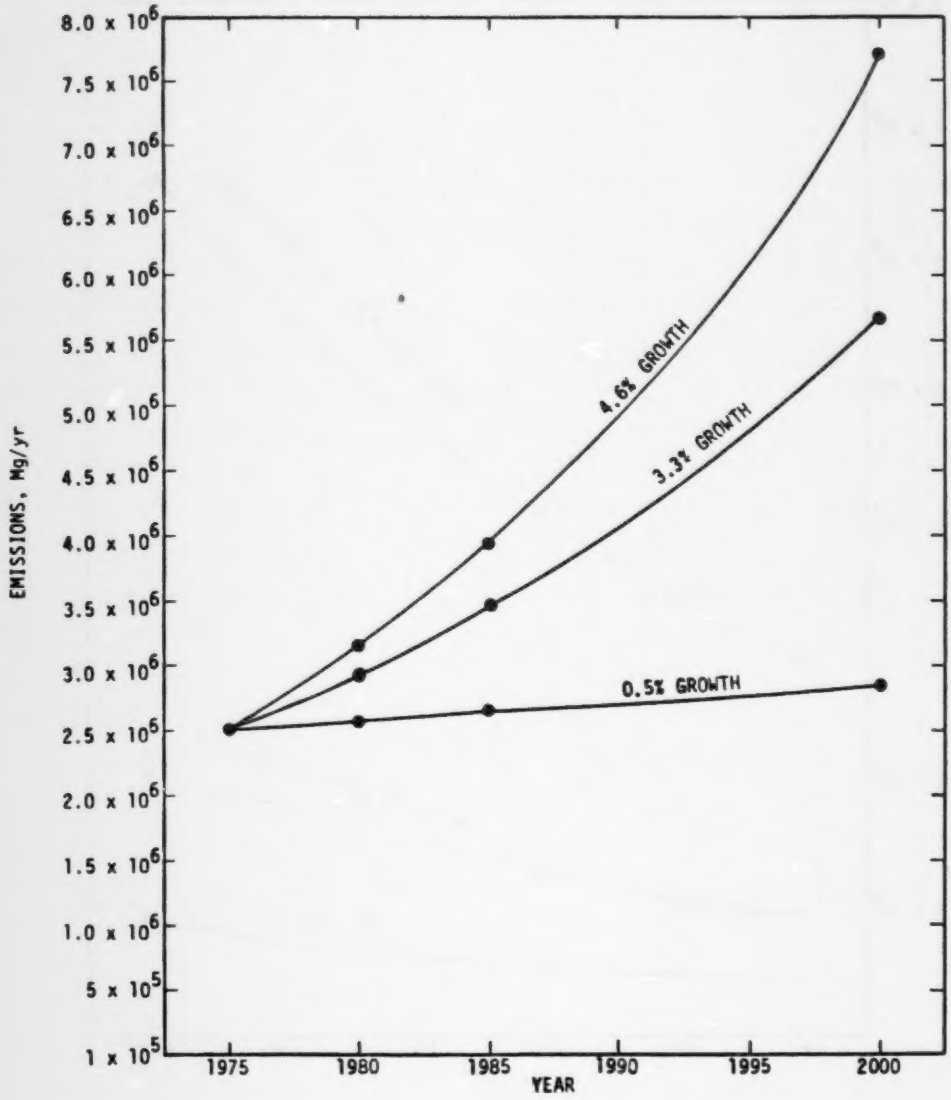


Figure 3-2. Projected total uncontrolled emissions of particulate for alternate growth rates through 2000.

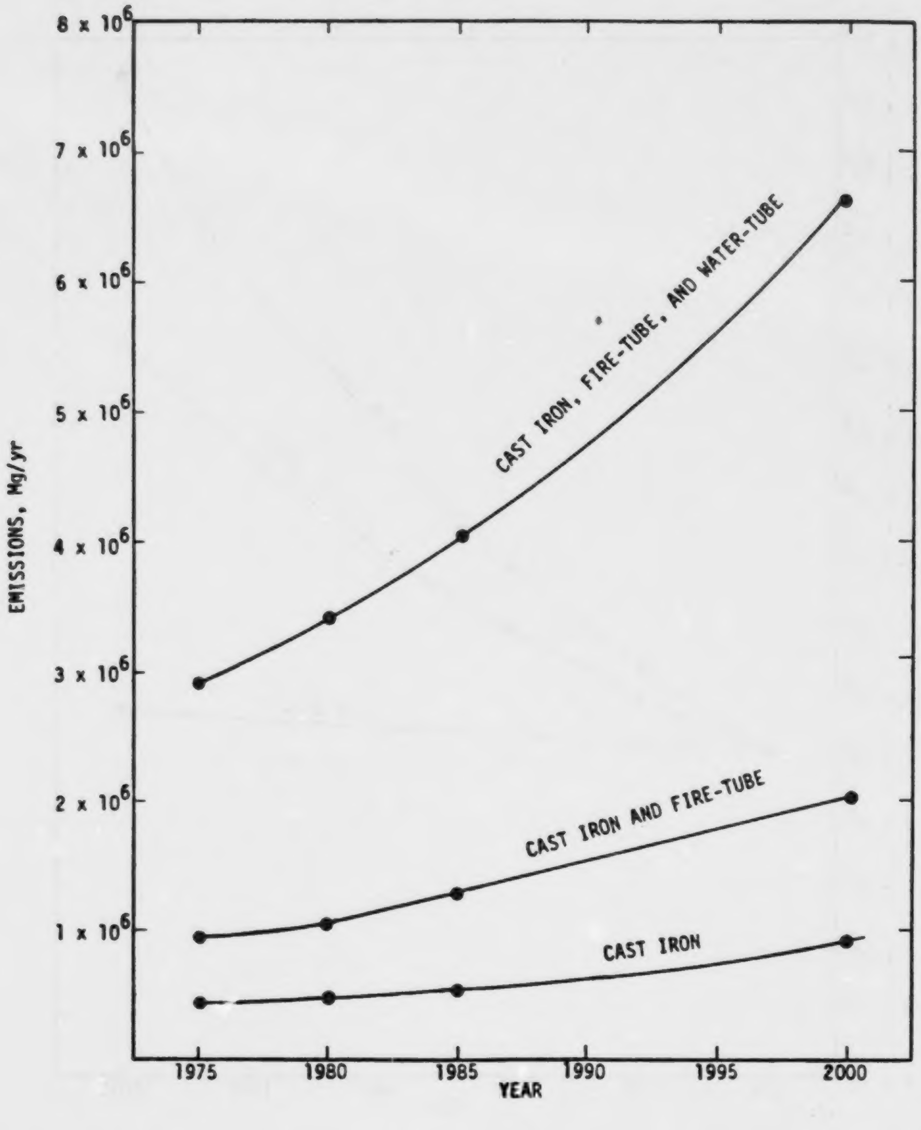


Figure 3-3. Projected total uncontrolled emissions of SO_x from the industrial/commercial boiler population through 2000.

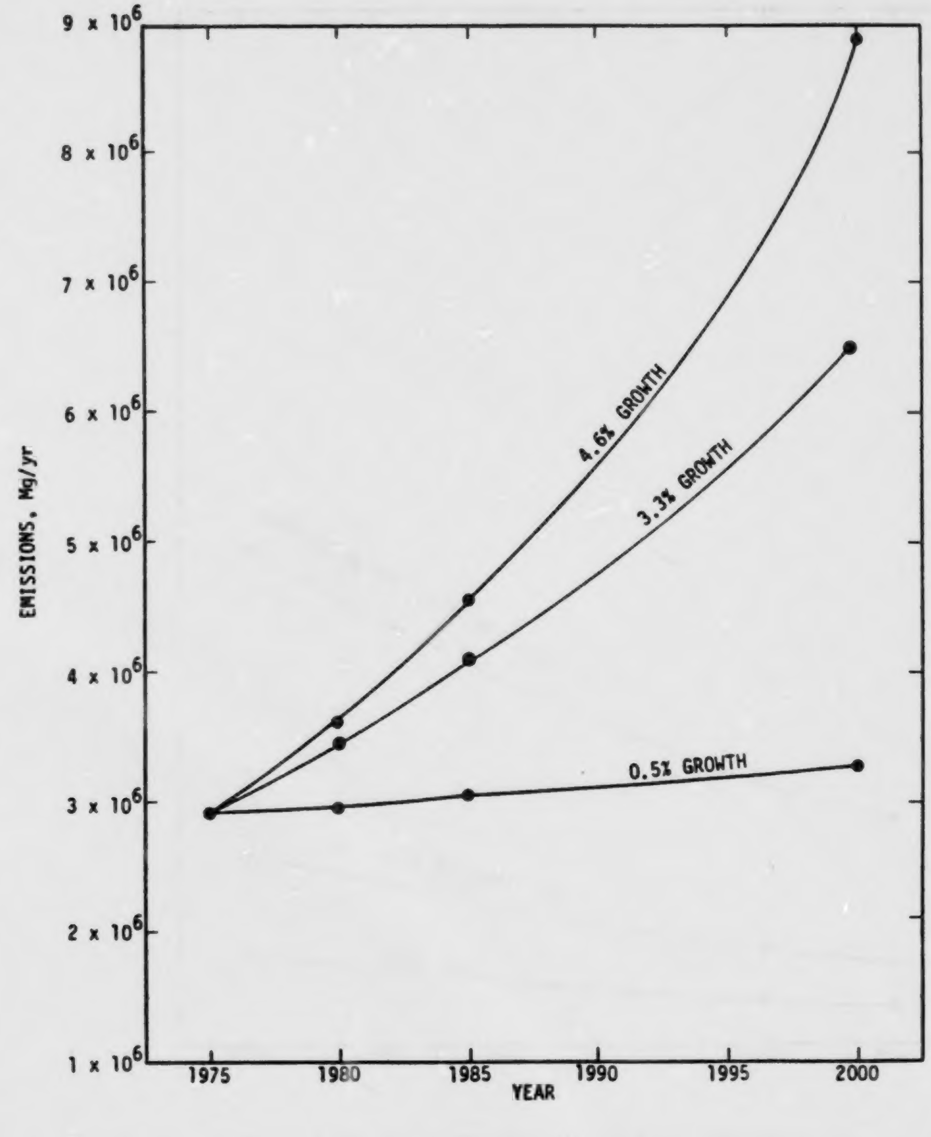


Figure 3-4. Projected total uncontrolled emissions of SO_x for alternate growth rates through 2000.

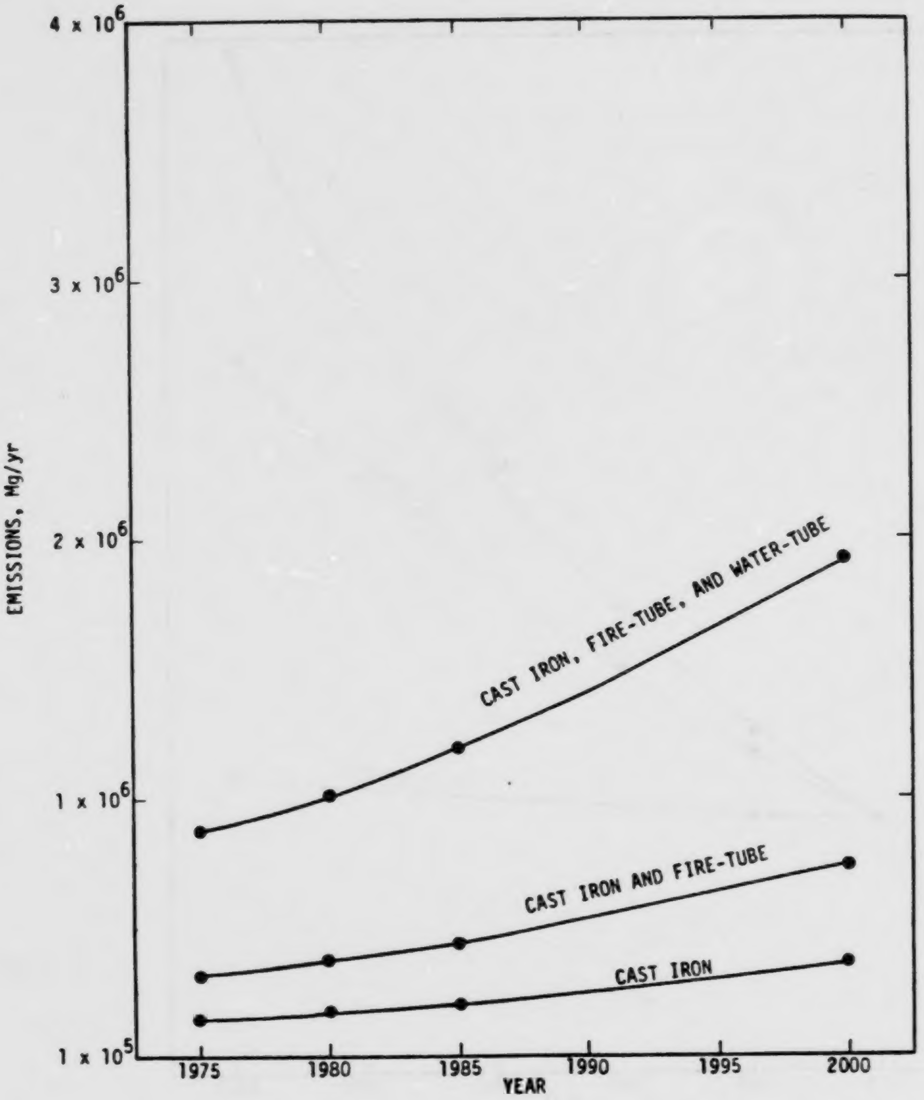


Figure 3-5. Projected total uncontrolled emissions of NO_x from the industrial/commercial boiler population through 2000.

sensitive to boiler configuration and are independent of fuel type. The projected emissions are based on the same boiler types as those in the 1975 data base. Coal conversion strategies would probably not have a great impact on the total NO_x emissions since rates of emissions from coal-fired units are not significantly different from oil- and natural-gas-fired units.

Total NO_x emissions were also calculated for annual growth rates of 4.6 percent and 0.5 percent and are presented in Figure 3-6 with the emissions for the 3.3 percent growth case for comparison.

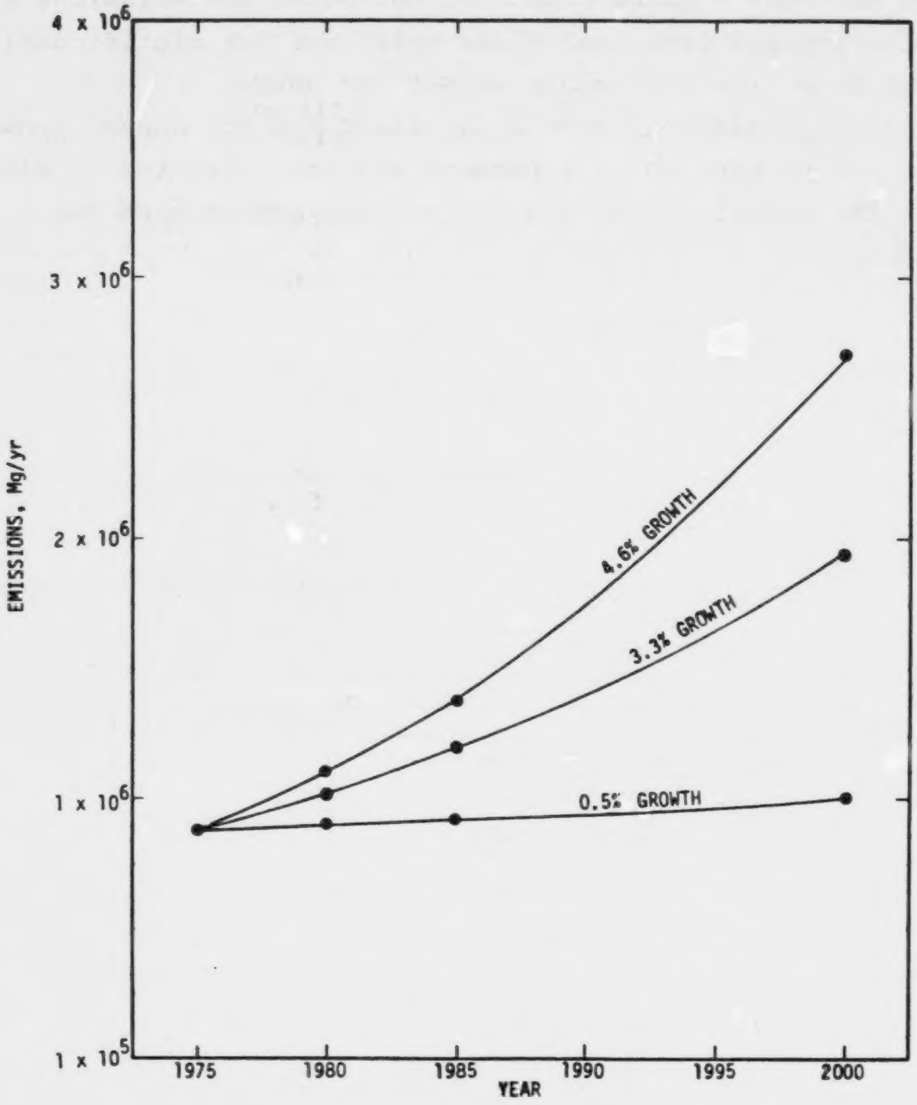


Figure 3-6. Projected total uncontrolled emissions of NO_x for alternate growth rates through 2000.

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SECTION 4

REPRESENTATIVE NEW BOILERS AND CHARACTERISTICS

To assess the relative impacts of possible regulations affecting industrial boilers, it is necessary to determine the costs of several different boiler types and emission control systems. The following subsections present the boilers selected for detailed evaluation, the rationale for their selection, and their design and operating characteristics.

4.1 TYPICAL INDUSTRIAL BOILERS

The following criteria were used in the selection of representative boilers:

- Extent of usage
- Potential for uncontrolled emissions of particulate matter, SO_x, and NO_x
- Representation of a cross section of the population
- Potential for future installation

Eleven boilers (Table 4-1) were selected as representative of the industrial boiler population. These boilers were proposed jointly by PEDCo, IERL-RTP, and OAQPS and were selected by agreement among industry representatives (ABMA), other contractors, and EPA representatives. The criteria each selected boiler satisfies are described in the following subsections.

4.1.1 Package, Scotch Fire-tube Boiler

A boiler that fires distillate oil or natural gas at a heat input of 4.4 MW thermal was selected as representative of the fire-tube boiler population. Because its capacity is near the maximum for fire-tube boilers (Appendix A), it is likely to have

TABLE 4-1. REPRESENTATIVE BOILERS SELECTED FOR EVALUATION

Boiler type	Fuel	Heat input, MW thermal (10^6 Btu/h)
Package, Scotch fire-tube	Distillate oil	4.4 (15)
Package, Scotch fire-tube	Natural gas	4.4 (15)
Package, water-tube, underfeed-stoker	Coal	8.8 (30)
Package, water-tube	Residual oil	8.8 (30)
Field-erected, water-tube, chain-grate-stoker	Coal	22.0 (75)
Package, water-tube	Residual oil	44.0 (150)
Package, water-tube	Distillate oil	44.0 (150)
Package, water-tube	Natural gas	44.0 (150)
Field-erected, water-tube spreader-stoker	Coal	44.0 (150)
Field-erected, water-tube	Pulverized coal	58.6 (200)
Field-erected, water-tube	Pulverized coal	117.2 (400)

the greatest impact on emissions. Distillate oil and natural gas are relatively clean fuels in terms of potential air emissions; however, these fuels are fired by the majority of the fire-tube units. Because distillate oil and natural gas are both widely used in fire-tube boilers, separate estimates were prepared for boilers firing each fuel. Sales data from ABMA for the 10-year period from 1966 to 1975 show that the Scotch fire-tube configuration is preferred, accounting for 50 percent of fire-tube sales (Locklin et al., 1974). These data also show that no coal-fired fire-tube boilers were sold during this 10-year period, thus eliminating them from consideration.

4.1.2 Package Water-tube Boiler With an Underfeed Stoker

A boiler that fires coal at a heat input of 8.8 MW thermal (30 x 10^6 Btu/h) was chosen as representative of small package water-tube units. The boiler has the potential for emitting large quantities of particulate matter, SO_x, and NO_x. About 60 percent of the coal-fired boilers in this size range use underfeed stokers (Locklin et al., 1974).

4.1.3 Package Water-tube Boilers

Boilers that fire residual oil at heat inputs of 8.8 MW thermal (30 x 10^6 Btu/h) and 44 MW thermal (150 x 10^6 Btu/h), distillate oil at 44 MW thermal (150 x 10^6 Btu/h), and natural gas at 44 MW thermal (150 x 10^6 Btu/h) were selected as representative of large package boilers. About 25 percent of the boilers in the range from 29 to 73 MW thermal (100 to 250 x 10^6 Btu/h) are shop-fabricated (Locklin et al., 1974). Three fuels were selected so that fuel impact could be represented in the overall analysis. The boilers have the potential for emitting significant quantities of SO_x and NO_x when firing residual oil.

4.1.4 Field-Erected Water-tube Boiler With Chain-grate Stoker

A boiler that fires coal at a heat input of 22 MW thermal (75 x 10^6 Btu/h) was selected as representative of small field-erected water-tube boilers. A boiler of this type has the potential for emitting significant, uncontrolled quantities of particulate matter, SO_x, and NO_x. The chain-grate stoker was chosen because it is a common fuel-firing mechanism for this size boiler.

4.1.5 Field-Erected Water-tube Boiler With Spreader Stoker

A boiler that fires coal at a heat input of 44 MW thermal (150×10^6 Btu/h) was selected as representative of large, field-erected, stoker-fired boilers. Seventy-five percent of the boilers in the 29 to 73 MW thermal (100 to 250×10^6 Btu/h) size range are field-erected, and 60 percent of the stoker-fired boilers in this size range utilize spreader stokers (Locklin et al., 1974). Spreader stokers have the potential for emitting large quantities of particulate matter, SO_x, and NO_x.

4.1.6 Field-Erected, Water-tube, Pulverized-Coal-Fired Boilers

Boilers that fire pulverized coal at heat inputs of 58.6 MW thermal (200×10^6 Btu/h) and 117.2 MW thermal (400×10^6 Btu/h) were selected as representative of pulverized-coal-fired boilers. Pulverized-coal-fired units account for 15 percent of the coal-fired boilers in the size range from 29 to 73 MW thermal (100 to 250×10^6 Btu/h) and 58 percent in the size range from 73 to 147 MW thermal (250 to 500×10^6 Btu/h). (Locklin et al., 1974.) These boilers have the potential for emitting significant quantities of particulate matter, SO_x, and NO_x.

The boiler configurations chosen are believed to represent designs most commonly purchased currently or projected to be purchased. An attempt was made to select a boiler for evaluation that contributes significantly to the emissions from the major class it represents and one on which possible emission limitations could have the most impact.

4.2 BOILER CHARACTERISTICS

Operational and design parameters had to be specified for the selected boilers before the costs of new boilers could be estimated and emission control equipment could be designed and costed. The following key operating and design parameters are required for each boiler:

- Boiler configuration
- Design heat input rate
- Fuel analysis
- Fuel consumption
- Emission rates
- Excess air usage
- Flue gas characteristics
- Load factor

The values determined for these operating and design parameters (Tables 4-2 through 4-11) are based on published data and practical knowledge of good boiler operating practices. The methodology used to determine these values is described in the following subsections.

4.2.1 Boiler Configuration

Boiler configuration was specified as an initial step in the selection of representative boilers, and the basis for each was described in Section 4.1.

4.2.2 Design Heat Input Rate

This rate is based on the available capacities of the boilers within the selected configurations. The selection of the capacity range reflects the greatest potential for generating emissions and the most common capacities within a particular boiler configuration. For example, Scotch fire-tube boilers are available in capacities ranging from 0.1 to 8.8 MW thermal (0.3 to 30 x 10^6 Btu/h). The largest portion of these boilers is in the 0.4 MW to 2.9 MW range, but boilers with a capacity of 4.4 MW thermal (15 x 10^6 Btu/h) are also quite common and their potential for emissions is larger than that of the boilers in the most common capacity range.

TABLE 4-2. DESIGN PARAMETERS FOR A DISTILLATE-OIL-FIRED, PACKAGE, SCOTCH FIRE-TUBE BOILER

Heat input, MW thermal (10^6 Btu/h)	4.4 (15)
Fuel rate, m^3/h (gal/h)	0.41 (108)
Analysis	
% Sulfur	0.5
% Ash	Trace
Heating value, MJ/m^3 (Btu/gal)	38,712 (139,000)
Excess air, %	15
Flue gas flow rate, m^3/s (acfm)	2.36 (5,000)
Flue gas temperature, °K (°F)	450 (350)
Load factor, %	45
Flue gas constituent, kg/h (lb/h)	
Fly ash	0.10 (0.22)
SO_2	3.47 (7.67)
NO_x	1.08 (2.38)
CO	0.24 (0.54)
HC as CH_4	0.05 (0.11)

TABLE 4-3. DESIGN PARAMETERS FOR A NATURAL-GAS-FIRED, PACKAGE, SCOTCH FIRE-TUBE BOILER

Heat input, MW thermal (10^6 Btu/h)	4.4 (15)
Fuel rate, m^3/h (ft^3/h)	424.8 (15,000)
Analysis	
% Sulfur	Trace
% Ash	Trace
Heating value, KJ/m^3 (Btu/ft^3)	37,218 (1000)
Excess air, %	15
Flue gas flow rate, m^3/s (acfm)	2.45 (5,200)
Flue gas temperature, °K (°F)	450 (350)
Load factor, %	45
Flue gas constituent, kg/h (lb/h)	
Fly ash	0.07 (0.15)
SO_2	0.005 (0.01)
NO_x	1.19 (2.63)
CO	0.12 (0.26)
HC as CH_4	0.02 (0.05)

TABLE 4-4. DESIGN PARAMETERS FOR A COAL-FIRED, PACKAGE, WATER-TUBE UNDERFEED BOILER

	Eastern high-sulfur coal	Eastern low-sulfur coal	Subbituminous coal
Heat input, MW thermal (10^6 Btu/h)	8.8 (30)	8.8 (30)	8.8 (30)
Fuel rate, kg/s (tons/h)	0.32 (1.27)	0.27 (1.09)	0.39 (1.56)
Analysis			
% Sulfur	3.5	0.9	0.60
% Ash	10.60	6.90	5.40
Heating value, kJ/kg (Btu/lb)	27,477 (11,800)	32,099 (13,800)	22,330 (9,600)
Excess air, %	50	50	50
Flue gas flow rate, m^3/s (acfm)	6.09 (12,900)	5.76 (12,200)	5.90 (12,500)
Flue gas temperature, °K (°F)	478 (400)	450 (350)	450 (350)
Load factor, %	60	60	60
Flue gas constituent, kg/h (lb/h)			
Fly ash	30.49 (67.31)	17.04 (37.61)	19.08 (42.12)
SO_2	76.52 (168.91)	16.89 (37.28)	16.13 (35.60)
NO_x	8.63 (19.05)	7.41 (16.35)	10.60 (23.40)
CO	1.15 (2.54)	0.99 (2.18)	1.41 (3.12)
HC as CH_4	0.58 (1.27)	0.49 (1.09)	0.71 (1.56)

TABLE 4-5. DESIGN PARAMETERS FOR A COAL-FIRED, FIELD-ERECTED WATER-TUBE, CHAIN-GRATE BOILER

	Eastern high-sulfur coal	Eastern medium-sulfur coal	Eastern low-sulfur coal	Subbituminous coal
Heat input, MW thermal (10^6 Btu/h)	22.0 (75)	22.0 (75)	22.0 (75)	22.0 (75)
Fuel rate, kg/s (tons/h)	0.80 (3.18)	0.72 (2.82)	0.69 (2.72)	0.99 (3.91)
Analysis				
% Sulfur	3.5	2.3	0.9	0.6
% Ash	10.6	13.2	6.9	5.4
Heating value, kJ/kg (Btu/lb)	27,447 (11,800)	30,703 (13,200)	32,099 (13,800)	22,330 (9,600)
Excess air, %	50	50	50	50
Flue gas flow rate, m^3/s (acfm)	15.24 (32,300)	14.73 (31,200)	14.21 (30,100)	14.82 (31,400)
Flue gas temperature, °K (°F)	478 (400)	450 (350)	450 (350)	450 (350)
Load factor, %	60	60	60	60
Flue gas constituent, kg/h (lb/h)				
Fly ash	76.35 (168.54)	84.31 (186.12)	42.51 (93.84)	47.82 (105.57)
SO_2	191.59 (422.94)	111.65 (246.47)	42.14 (93.02)	40.38 (89.15)
NO_x	21.61 (47.70)	19.16 (42.30)	18.48 (40.80)	26.57 (58.65)
CO	2.88 (6.36)	2.55 (5.64)	2.46 (5.44)	3.54 (7.82)
HC as CH_4	1.44 (3.18)	1.28 (2.82)	1.23 (2.72)	1.77 (3.91)

TABLE 4-6. DESIGN PARAMETERS FOR RESIDUAL-OIL-FIRED, PACKAGE, WATER-TUBE BOILERS

Heat input, MW thermal (10^6 Btu/h)	8.8	(30)	44.0	(150)
Fuel rate, m^3/h (gal/h)	0.76	(200)	3.79	(1000)
Analysis				
% Sulfur	3.0		3.0	
% Ash	0.1		0.1	
Heating value, MJ/m^3 (Btu/gal)	41,714	(149,800)	41,714	(149,800)
Excess air, %	15		15	
Flue gas flow rate, m^3/s (acfm)	4.62	(9800)	22.04	(46,700)
Flue gas temperature, °K (°F)	478	(400)	478	(400)
Load factor, %	55		55	
Flue gas constituents, kg/h (lb/h)				
Fly ash	2.99	(6.60)	14.95	(33.0)
SO_2	42.73	(94.20)	213.36	(471.0)
NO_x	5.44	(12.0)	27.18	(60.0)
CO	0.45	(1.0)	2.27	(5.0)
HC as CH_4	0.09	(0.20)	0.45	(1.0)

TABLE 4-7. DESIGN PARAMETERS FOR A DISTILLATE-OIL-FIRED, PACKAGE, WATER-TUBE BOILER

Heat input, MW thermal (10^6 Btu/h)	44.0	(150)
Fuel rate, m^3/h (gal/h)	4.09	(1080)
Analysis		
% Sulfur	0.5	
% Ash	Trace	
Heating value, MJ/m^3 (Btu/gal)	38,712	(139,000)
Excess air, %	15	
Flue gas flow rate, m^3/s (acfm)	21.78	(46,200)
Flue gas temperature, °K (°F)	450	(350)
Load factor, %	55	
Flue gas constituents, kg/h (lb/h)		
Fly ash	0.98	(2.16)
SO_2	34.78	(76.61)
NO_x	10.75	(23.74)
CO	2.44	(5.40)
HC as CH_4	0.49	(1.08)

TABLE 4-8. DESIGN PARAMETERS FOR A NATURAL-GAS-FIRED, PACKAGE, WATER-TUBE BOILER

Heat input, MW thermal (10^6 Btu/h)	44.0	(150)
Fuel rate, m^3/h (ft^3/h)	4,248	(150,000)
Analysis		
% Sulfur	Trace	
% Ash	Trace	
Heating value, MJ/m^3 (Btu/gal)	37,218	(1000)
Excess air, %	15	
Flue gas flow rate, m^3/s (acfm)	22.15	(46,900)
Flue gas temperature, °K (°F)	450	(350)
Load factor, %	55	
Flue gas constituents, kg/h (lb/h)		
Fly ash	0.68	(1.50)
SO_2	0.04	(0.09)
NO_x	11.92	(26.26)
CO	1.16	(2.56)
HC as CH_4	0.20	(0.46)

TABLE 4.9. DESIGN PARAMETERS FOR A COAL-FIRED, FIELD-ERECTED, WATER-TUBE, SPREADER-STOKER BOILER

	Eastern high-sulfur coal		Eastern low-sulfur coal		Subbituminous coal	
Heat input, MW thermal (10^6 Btu/h)	44.0	(150)	44.0	(150)	44.0	(150)
Fuel rate, kg/s (tons/h)	1.60	(6.36)	1.37	(5.43)	1.97	(7.81)
Analysis						
% Sulfur	3.5		0.9		0.6	
% Ash	10.6		6.9		5.4	
Heating value, kJ/kg (Btu/lb)	27,447	(11,800)	32,099	(13,800)	22,330	(9,600)
Excess air, %	50		50		50	
Flue gas flow rate, m^3/s (acfm)	30.58	(64,800)	28.69	(60,800)	29.64	(62,800)
Flue gas temperature, °K (°F)	478	(400)	450	(350)	450	(350)
Load factor, %	60		60		60	
Flue gas constituent, kg/h (lb/h)						
Fly ash	397.01	(876.41)	220.64	(487.07)	248.36	(548.26)
SO_2	383.18	(845.88)	84.12	(185.71)	80.67	(178.07)
NO_x	43.22	(95.40)	36.90	(81.45)	53.07	(117.15)
CO	5.76	(12.72)	4.92	(10.86)	7.08	(15.62)
HC as CH_4	2.88	(6.36)	2.46	(5.43)	3.54	(7.81)

TABLE 4-10. DESIGN PARAMETERS FOR A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER WITH A HEAT INPUT OF 58.6 MW THERMAL (200 x 10^6 Btu/h)

	Eastern high-sulfur coal	Eastern low-sulfur coal	Subbituminous coal
Fuel rate, kg/s (tons/h)	2.13 (8.47)	1.83 (7.25)	2.63 (10.42)
Analysis			
% Sulfur	3.5	0.9	0.6
% ash	10.6	6.9	5.4
Heating value, kJ/kg (Btu/lb)	27,447 (11,800)	32,099 (13,900)	22,330 (9,600)
Excess air, %	30	30	30
Flue gas flow rate, m^3/s (acfm)	35.30 (74,800)	33.32 (70,600)	34.55 (73,200)
Flue gas temperature, °K (°F)	478 (400)	450 (350)	450 (350)
Load factor, %	60	60	60
Flue gas constituent, kg/h (lb/h)			
Fly ash	650.74 (1436.51)	362.58 (800.40)	407.83 (900.29)
SO_2	510.31 (1126.51)	112.32 (247.95)	107.62 (237.56)
NO_x	69.06 (152.46)	59.12 (130.50)	84.96 (187.56)
CO	3.84 (8.47)	3.28 (7.25)	4.72 (10.42)
HC as CH_4	1.15 (2.54)	0.99 (2.18)	1.42 (3.13)

TABLE 4-11. DESIGN PARAMETERS FOR A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER WITH A HEAT INPUT OF 117.2 MW THERMAL (400 x 10^6 Btu/h)

	Eastern high-sulfur coal		Eastern medium-sulfur coal		Eastern low-sulfur coal		Subbituminous coal	
Fuel rate, kg/s (tons/h)	4.27	(16.95)	3.82	(15.14)	3.65	(14.49)	5.25	(20.83)
Analysis								
% Sulfur	3.5		2.3		0.9		0.6	
% Ash	10.6		13.2		6.9		5.4	
Heating value, kJ/kg (Btu/lb)	27,447	(11,800)	30,703	(13,200)	32,099	(13,800)	22,330	(9,600)
Excess air, %	30		30		30		30	
Flue gas flow rate, m^3/s (acfm)	70.63	(149,600)	71.35	(151,200)	66.80	(141,500)	68.89	(146,000)
Flue gas temperature, °K (°F)	478	(400)	478	(400)	450	(350)	450	(350)
Load factor, %	60		60		60		60	
Flue gas constituent, kg/h (lb/h)								
Fly ash	1304.0	(2874.72)	1450.4	(3197.57)	725.6	(1599.70)	816.3	(1799.71)
SO_2	1022.6	(2254.35)	600.2	(1323.24)	224.8	(495.56)	215.4	(474.92)
NO_x	138.4	(305.10)	123.6	(272.52)	118.3	(260.82)	170.1	(374.94)
CO	7.7	(16.95)	6.9	(15.14)	6.6	(14.49)	9.4	(20.83)
HC as CH_4	2.3	(5.09)	2.1	(4.54)	2.0	(4.34)	2.8	(6.24)

4.2.3 Fuel Analysis

Fuel type for each representative boiler was specified as part of the initial selection process. The fuel analyses presented in Table 4-12 for natural gas and distillate and residual oil were determined from data about "average" fuels presented by Babcock & Wilcox (1972). The Babcock & Wilcox analysis of Birmingham natural gas was selected as average. The values selected for distillate oil represent No. 2 fuel oil; they were selected from the middle of the ranges presented, except for sulfur content, which was chosen from the upper part of the range for evaluation of a distillate oil with a relatively high sulfur content. The analysis for the residual oil was selected from the range of values given for No. 6 fuel oil; again, all values were taken from the middle of the ranges except the sulfur value, which comes from the upper part of the range so that a high-sulfur residual oil can be evaluated.

Four coal analyses were used to represent the major coal-producing areas and classes of coals available in the United States. Data from Babcock & Wilcox (1972) served as the basis for the analyses of eastern high-sulfur, high-ash, bituminous coal; eastern low-sulfur, low-ash, low-moisture, bituminous coal; and western low-sulfur, low-ash, high-moisture, subbituminous coal. Versar, Inc., provided the analysis of eastern medium-sulfur, high-ash, low-moisture, bituminous coal.

4.2.4 Fuel Consumption

Given the heat input rate specified for each representative boiler in Table 4-1, fuel consumption was calculated by dividing the heat input rate by the heating value of the fuel used. For example, if a package, water-tube, underfeed stoker with a heat input rate of 8.8 MW thermal (30 x 10^6 Btu/h) fires eastern coal at 27,447 kJ/kg, the amount of fuel required is equal to 8800 kJ/s ÷ 27,447 kJ/kg, or 0.32 kg/s.

TABLE 4-12. ULTIMATE ANALYSES OF FUELS SELECTED FOR THE REPRESENTATIVE BOILERS[a]

Fuel	Composition, % by weight							Heating value, kJ/kg (Btu/lb)
	Water	Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Ash	
Natural gas	0.02	69.26	22.67	8.05	Trace	Trace	0	50,707 (21,800)
Distillate oil	0.05	87.17	12.28	Trace	Trace	0.50	Trace	45,346 (19,500)
Residual oil	0.08	86.62	10.20	Trace	Trace	3.00	0.10	43,043 (18,500)
Eastern high-sulfur, high-ash coal	8.79	64.80	4.43	1.30	6.56	3.54	10.58	27,447 (11,800)
Eastern medium-sulfur, high-ash coal	0.80	74.80	4.56	1.19	3.17	2.28	13.20	30,703 (13,200)
Eastern low-sulfur, low-ash coal	2.54	78.64	4.70	1.48	4.88	0.90	6.86	32,099 (13,800)
Western low-sulfur, low-ash coal	20.80	57.60	3.20	1.20	11.20	0.60	5.40	22,330 (9,600)

[a] All analyses are based on engineering judgments by PEDCo about information from Babcock & Wilcox (1972), except for the analysis of eastern medium-sulfur, high-ash coal, which Versar, Inc., provided in a memo of March 22, 1979, to J. Kilgroe, IERL, Research Triangle Park, North Carolina.

Because input capacities are specified, it is not necessary to consider the efficiencies of boiler heat transfer or fuel burning.

4.2.5 Emission Rates

All emission factors for particulates, sulfur oxides, nitrogen oxides, carbon monoxide, and hydrocarbons for the representative boilers were obtained from AP-42 (EPA, 1977). Each representative boiler type and fuel are listed in the emission factor tables (in Section 3.1) with the exception of the field-erected, water-tube, spreader-stoker boiler with a heat input of 44 MW thermal (150 x 10^6 Btu/h). Emissions from this boiler were assumed to resemble most closely those from spreader-stoker, coal-fired, industrial boilers with a heat input between 2.9 and 29.3 MW thermal (10 and 100 x 10^6 Btu/h); therefore these emission factors were used.

The factors presented in AP-42 are generally dependent upon the analysis and amount of the fuel burned, and they represent uncontrolled emissions under normal operating conditions. The emission rate for a particular time period is determined by applying the emission factor to the amount of fuel burned in the time period, using fuel analysis parameters where appropriate. For example, the particulate emission factor applicable to the package, water-tube, underfeed-stoker boiler firing eastern high-sulfur coal is (2.5 x A) kg/10^3 kg of coal burned, where A is the ash content of the fuel. Eastern high-sulfur coal has an ash content of 10.60 percent and is burned at a rate of 0.32 kg/s. The particulate emission rate is calculated as follows:

$$\text{Particulate emissions} = 2.5(10.60)\ \text{kg}/10^3\ \text{kg coal burned} \times 0.32\ \text{kg coal burned/s} \times 1 \times 10^3\ \text{kg}/1000\ \text{kg} \times 3600\ \text{s/h}$$

$$= 30.5\ \text{kg/h}\ (61.31\ \text{lb/h})$$

The same approach is used for calculating emissions from each representative boiler/fuel type combination.

4.2.6 Excess Air Usage

The amount of excess air selected for each boiler type is based on practical knowledge of good boiler operating practices. Table 4-13 presents ranges (percentages bv weight) of excess air common to different boiler types. A value for each representative boiler was selected out of this range, based upon previous experience and data on boiler operating characteristics.

A mass balance was then performed to obtain the amount of excess air. The combustion air was assumed to have a temperature of 27°C (80°F), a relative humidity of 60 percent, and a pressure of 101 kPa (14.7 psi). The amount of air required for complete combustion of the fuel was calculated on a molal basis from the ultimate analysis of the fuel and the emission rates of the various flue gas constituents.

An example of the procedure is shown below using the package, water-tube, underfeed-stoker boiler with a heat input of 8.8 MW thermal (30 x 10^6 Btu/h).

The molal configuration for each of the gaseous constituents of the flue gas (determined by emission factors) is calculated by dividing the mass rate by the molecular weight of the constituent. The results for the example boiler are shown below:

Constituent	moles/h
Carbon monoxide (CO)	0.09
Hydrocarbons (as CH_4)	0.07
Sulfur dioxide (SO_2)	2.80
Nitrogen oxides (as NO_2)	0.23

The molal rate of each component is then calculated using the fuel mass rate per hour and the ultimate analysis of the fuel. The results for the example boiler are tabulated below:

TABLE 4-13. TYPICAL AMOUNTS OF EXCESS AIR SUPPLIED TO FUEL-BURNING EQUIPMENT[a]

Fuel	Type of burners	Excess air, % by weight
Pulverized coal	Partially water-cooled for dry ash removal	15-40
Coal	Spreader stoker	30-60
	Chain-grate and traveling-grate stokers	15-50
	Underfeed stoker	20-50
Fuel oil	Multifuel and flat-flame	10-20
Natural gas	Multifuel	7-15

[a] Babcock & Wilcox, 1963.

Fuel constituent	Mass rate, kg/h (lb/h)	Molal rate
Carbon (C)	12.44 (1646)	137.1
Hydrogen (H_2)	0.85 (113)	56.1
Sulfur (S)	0.68 (90)	2.8
Oxygen (O_2)	1.26 (167)	5.2
Nitrogen (N_2)	0.25 (33)	1.2
Water (H_2O)	1.69 (223)	12.4

The remaining flue gas constituents (CO_2, H_2O, N_2) are calculated by molal balance by subtracting the calculated moles of emissions (AP-42) from the moles of equivalent components in the fuel. For example, the CO and CH_4 represent part of the carbon from the fuel. Assuming the remaining carbon is oxidized to CO_2, the molal quantity of CO_2 is 137.17 moles of carbon minus 0.09 moles of CO minus 0.07 moles of CH_4 or 137.01 moles of CO_2. The results of similar analyses for the other flue gas constituents of the example boiler are as follows:

Constituent	Molal quantity
CO_2	137.0
H_2O	68.5
N_2	1.1

To calculate the stoichiometric oxygen required, each flue gas constituent is examined in terms of equivalent oxygen content. The following is a presentation of data for the example boiler.

Flue gas constituent	Moles per hour	Moles of O_2 per mole constituent	Moles of O_2 per hour
CO_2	137.0	1.0	137.0
CO	0.09	0.5	0.4
CH_4	0.07	0.0	0.0
SO_2	2.80	1.0	2.8
H_2O	68.5	0.5	34.2
NO_x (as NO_2)	0.23	1	0.23
N_2	1.1	0.0	0.0
Total			174.27

Of the 174.3 moles of O_2 required, the O_2 in the coal supplies 5.2 moles and the H_2O in the coal supplies 6.2 moles. Therefore the theoretical requirement from the combustion air is 162.9 moles of O_2. The excess air for this boiler is 50 percent of stoichiometric. Therefore the total oxygen required is 1.5 times the theoretical requirement, or 244.4 moles. It was assumed that the combustion air is 21 percent oxygen and 79 percent nitrogen. Therefore the N_2 required is 919 moles. The weight of dry air supplied is then 15,256 kg/h (33,564 lb/h). At the previously assumed combustion air conditions, 0.0212 mole of water is contained in the wet air per mole of dry air (24 moles of H_2O total). The total wet combustion air supplied is then 15,453 kg/h (33,996 lb/h).

4.2.7 Flue Gas Characteristics

The volume of the exit flue gas is dependent upon its composition, the amount of excess air, and the exit temperature. The total moles of the various flue gas constituents was determined for each boiler in the excess air calculations. At standard conditions, the volume of a mole of gas is 10.2 m^3 (359 ft^3), assuming ideal behavior. Therefore the volume of the flue gas at standard conditions can be calculated.

The actual volume of the flue gas must be calculated at the flue gas temperature. Assumed temperatures of the exit flue gas from each boiler were based on typical temperatures from previous boiler studies. The calculated volumes of flue gas were then adjusted from standard conditions to the actual temperature. It was assumed that the flue gas pressure is constant at 101 kPa (14.7 psi).

For example, for the package, water-tube, underfeed-stoker boiler with a heat input of 8.8 MW thermal (30 x 10^6 Btu/h), total dry flue gas was calculated to be 1135.9 moles. On a wet basis, flue gas was calculated to be 1228.4 moles. At the assumed exhaust temperature of 478°K (400°F) the flue gas volume is:

$$1228.4 \text{ moles/h} \times 10.2 \text{ m}^3\text{/mole} \times \frac{478°\text{K}}{273°\text{K}} =$$

$$21{,}938 \text{ m}^3\text{/h } (775{,}204 \text{ ft}^3\text{/h})$$

$$21{,}938 \text{ m3/h} \div 3600 \text{ s/h} = 6.09 \text{ m}^3\text{/s } (12{,}800 \text{ ft}^3\text{/min})$$

4.2.8 Load Factor

Assumed load factors for the representative boilers were based on ranges of load factors for industrial boilers. Battelle (Locklin, et al., 1974) estimated load factors in industrial/commercial boilers to range from 30 to 80 percent. Selection of values from the range for each representative boiler was based on previous boiler studies and data on typical load factors. The load factors are believed to be representative of new industrial boilers supplying process steam. The overall industry and commercial load factors discussed in Section 2 are lower because they reflect standby capacity and seasonal use.

REFERENCES FOR SECTION 4

Babcock & Wilcox. 1963. Steam - Its Generation and Use, Thirty-seventh Edition. New York City.

Babcock & Wilcox. 1972. Useful Tables for Engineers and Steam Users, Twelfth Edition. New York City.

Locklin, D.W., H.H. Krause, A.A. Putman, E.L. Kropp, W.T. Reid, and M.A. Duffy. 1974. Design Trends and Operating Problems in Combustion Modification of Industrial Boilers. EPA R-802402, Battelle-Columbus Laboratories, Columbus, Ohio.

U.S. EPA. 1975. Compilation of Air Pollutant Emission Factors, AP-42, Second Edition.

SECTION 5

BASIS FOR COST EVALUATIONS

To evaluate the economic impact of controlling pollution from new industrial and commercial boilers, one must determine the cost of the various types of new boilers and also the cost of the pollution control equipment. The percentage increase in cost of a controlled system over that of an uncontrolled system can then be determined. Both the capital cost and the annual operating cost are evaluated. The capital cost is then translated into an annual cost component and added to the annual operating cost to derive an "annualized" cost estimate.

The design parameters and operating characteristics of the boilers to be controlled strongly influence the cost. Section 4 described the basis for establishing a standard set of design parameters and operating characteristics for the boiler and the associated pollution control equipment. The next step is to establish a common basis for determining costs. This section presents a standardized procedure and rationale for determining the capital cost, annual operating cost, and annualized cost of new boilers and pollution abatement equipment.

Capital costs include both direct and indirect cost components. Section 5.1 describes the items to be included in both categories, as well as the normal range of values for indirect cost components. The reliability of cost estimates developed with the guidelines presented here is expected to be plus or minus 30 percent. This is the degree of accuracy expected for a study estimate in which only approximate specifications for sizes and materials are available. If the control process is untried, however, reliability can be as poor as plus 100 percent or minus 50 percent.

As a process is developed, the design parameters and equipment specifications are established with greater certainty, and cost estimates become more accurate.

Recommended formats for presentation of capital and annual costs are presented in Section 5.2. These are provided as guidelines to ensure consistency in cost estimates for industrial boiler control systems.

Section 5.3 gives recommended values for unit prices to be used in estimating costs.

5.1 COST ELEMENTS

5.1.1 Capital Costs

The capital cost of a boiler or an emission reduction system consists of the direct and indirect costs incurred up to the successful commissioning of the facility. The first step in determining these costs is specification of the battery limits of the system. This definition of what is included in the system is used to develop an equipment list. Direct costs include the cost of the various equipment items and cost of the labor and material required for installing the items and interconnecting the system. The cost of land required for the equipment is also a direct cost. Indirect costs are costs entailed in developing the overall facility, but not attributable to a specific equipment item. Indirect costs include such items as construction and field expenses, engineering, construction fees, startup, performance tests, and contingencies. Working capital, also included under indirect costs, represents the assets required to cover items needed for current operation of a facility. It includes raw material stocks, in-process inventory, product inventory, accounts receivable, and current obligations for employee wages and other services.

Direct Costs--

The "bought-out" cost of equipment and auxiliaries and the cost of installation are considered direct costs. The costs of equipment and auxiliaries are obtained from vendor estimates or pricing catalogs. Transportation costs are then added to obtain the total delivered cost. Installation costs include costs of foundations, supporting structures, enclosures, piping, ducting, stacks, control panels, instrumentation, insulation, painting, and similar items. Costs for interconnection of postcombustion control equipment items include site development and construction of access roads and walkways. The cost of administrative facilities is also considered part of the direct installation costs. These items are usually estimated as a percentage of the equipment cost. When data are available on actual installation requirements (such as cubic meters of concrete for foundations or total length of connecting pipe), the installation costs should be calculated directly. The costs of research and development and the cost of lost production during installation and startup are not included.

Indirect Costs--

Indirect costs are those that cannot be attributed to specific equipment. Items included in indirect costs are described below:

> Engineering costs: includes administrative, process, project, and general engineering; design and related functions for specifications; bid analysis; special studies; cost analysis; accounting; reports; purchasing; procurement; travel expenses; living expenses; expediting; inspection; safety; communications; modeling; pilot plant studies; royalty payments during construction; training of plant personnel; field engineering; safety engineering; and consultant services.
>
> Construction and field expenses: includes costs for temporary field offices; warehouses; craft sheds; fabrication shops; miscellaneous buildings; temporary utilities; temporary sanitary facilities; temporary roads; fences; parking lots; storage areas; field computer services; equipment fuel and lubricants; mobilization and demobilization; field office

supplies; telephone and telegraph; time clock system; field supervision; equipment rental; small tools; equipment repair; scaffolding; and freight.

Contractor's fee: includes costs of field labor payroll; supervision field office; administrative personnel; travel expenses; permits; licenses; taxes; insurance; field overhead; legal liabilities; and labor relations.

Startup: includes costs associated with system startup and shakedown.

Performance test: includes cost of a one-time test to determine compliance with equipment performance guarantees.

Contingency costs: an account set up to deal with uncertainties such as unforeseen escalation in costs, malfunctions, equipment design alterations, and overlooked cost items.

Working capital: includes costs of raw material stocks and a fund to cover operation and maintenance of a system for a given period of time. A period of 90 days is recommended for boiler installations.

Indirect costs are determined as a percentage of the installed equipment cost items and vary with each project. Table 5-1 gives typical ranges of each indirect capital cost factor as well as values recommended for use in cost estimates. These values are provided solely for guidance; where other values are specified, a rationale for their use should be given.

The month and year on which costs are based must be specified to allow cost comparisons on a consistent basis. It is recommended that all costs be adjusted to June 30, 1978. Standard indexes, such as the chemical engineering cost index, should be used to adjust costs to this date, and details of the adjustment method should be specified.

5.1.2 Annual Costs

Annual operating costs of emission control systems also consist of two components: operation and maintenance, with associated overhead, and capital-related expenses. Operation and maintenance charges include those for labor, raw materials,

Table 5-1. TYPICAL VALUES[a] FOR INDIRECT CAPITAL COSTS

Cost item	Range of values
Engineering	8 to 20 percent of installed cost. High value for small projects; low value for large projects. Recommend 10 percent
Construction and field expenses	7 to 20 percent of installed cost. Recommend 10 percent
Contractor's fee	10 to 15 percent of installed cost. Recommend 10 percent
Shakedown	1 to 6 percent of installed cost. Recommend 2 percent
Performance test	Minimum value of $2000.
Contingency	10 to 30 percent of total direct and indirect costs dependent upon accuracy of estimate. Recommend 20 percent
Working capital	15 to 35 percent of the total annual operation and maintenance costs. Recommend 25 percent

[a] Values are based on material from 18 sources that are listed at the end of Section 5.

utilities, and waste disposal required to operate the system on a day-to-day basis. Capital-related expenses are those associated with owning the equipment, including depreciation, taxes, insurance, and interest on borrowed capital.

Operation and Maintenance Costs--

Utilities: includes water for process use and cooling; steam; electricity to operate controls, fans, motors, pumps, valves, and lighting; and fuel if required.

Raw materials: includes any chemicals required for operation of the system.

Operating labor: includes supervision and the skilled and unskilled labor required to operate, monitor, and control the system.

Maintenance and repairs: consists of manpower and materials needed to keep the system operating efficiently.

Byproduct costs: for systems producing a salable product, a credit for that product; for systems producing a product for disposal, the cost of disposal.

Fuel costs: where a fuel other than the normal supply is used, the incremental cost of the fuel over and above normal costs.

Another component of operating cost is overhead, which represents a business expense that is not charged directly to a particular part of the process but is allocated to it. Overhead costs include administrative, safety, engineering, legal, and medical services; payroll expenses including FICA; employee benefits; and public relations. Overhead costs are usually presented as payroll overhead and plant overhead. Following are recommended values for each:

Payroll overhead = 30 percent of direct labor

Plant overhead = 26 percent of labor and materials.

Capital-Related Expenses--

The capital investment in a facility is generally translated into annual capital charges. These charges, along with the annual operating costs, represent the total annualized cost of a given system.

EPA classifies annual capital-related charges for cost purposes under the following components: general and administrative costs, taxes, insurance; a capital-recovery factor, which represents a levelized principal and interest payment; and interest on working capital. The first three components are set at a total of 4 percent of depreciable investment. The capital-recovery factor should be determined at 10 percent interest over the life of a facility. Typical useful lifespans of some pollution control devices are 20 years for an electrostatic precipitator, 10 years for a venturi scrubber, and 20 years for a fabric filter system. For other devices, a value for useful life should be based on experience or on reliable data. Capital-recovery factors for various time spans are presented in Table 5-2. For example, with an annual interest rate of 10 percent and an equipment life of 20 years, the capital-recovery factor is 0.11747 or 11.75 percent, which is the portion of the original capital investment set aside per year to cover depreciation of the equipment.

The interest on working capital is also 10 percent, representing the cost of foregoing other investment use of this fund.

5.2 COST ESTIMATING FORMAT

To provide consistent cost estimates for the ITAR studies, a standardized format was developed under the guidance of the Economic Analysis Branch, Office of Air Quality, Planning, and Standards. Adherence to the format will allow a direct comparison of the costs of various control technologies and of each cost category. Table 5-3 presents the format for capital costs. Table 5-4 presents the format for annual costs.

TABLE 5-2. CAPITAL RECOVERY FACTORS

Equipment life, yr	Annual compounded interest rate, %							
	5	6	7	8	10	12	15	20
1	1.05000	1.06000	1.07000	1.08000	1.10000	1.12000	1.15000	1.20000
2	0.53780	0.54544	0.55309	0.56077	0.57619	0.59170	0.61512	0.65455
3	0.36721	0.37311	0.38105	0.38803	0.40211	0.41635	0.43798	0.47473
4	0.28201	0.28859	0.29523	0.30192	0.31547	0.32923	0.35027	0.38629
5	0.23097	0.23740	0.24389	0.25046	0.26380	0.27741	0.29832	0.33438
6	0.19702	0.20336	0.20980	0.21632	0.22961	0.24323	0.26424	0.30071
7	0.17282	0.17914	0.18555	0.19207	0.20541	0.21912	0.24036	0.27742
8	0.15472	0.16104	0.16747	0.17401	0.18744	0.20130	0.22285	0.26061
9	0.14069	0.14702	0.15349	0.16008	0.17464	0.18768	0.20957	0.24808
10	0.12950	0.13587	0.14238	0.14903	0.16275	0.17698	0.19925	0.23852
11	0.12039	0.12679	0.13336	0.14008	0.15396	0.16842	0.19107	0.23110
12	0.11283	0.11928	0.12590	0.13270	0.14676	0.16144	0.18448	0.22526
13	0.10646	0.11296	0.11965	0.12652	0.14078	0.15568	0.17911	0.22062
14	0.10102	0.10758	0.11434	0.12130	0.13575	0.15087	0.17469	0.21689
15	0.09634	0.10296	0.10979	0.11683	0.13147	0.14682	0.17102	0.21388
16	0.09227	0.09895	0.10586	0.11298	0.12782	0.14339	0.16795	0.21144
17	0.08870	0.09544	0.10342	0.10963	0.12466	0.14046	0.16537	0.20944
18	0.08555	0.09236	0.09941	0.10670	0.12193	0.13794	0.16319	0.20781
19	0.08275	0.08962	0.09675	0.10413	0.11955	0.13576	0.16134	0.20646
20	0.08024	0.08718	0.09439	0.10185	0.11747	0.13388	0.15976	0.20536

(continued)

TABLE 5-2 (continued)

Equipment life, yr	Annual compounded interest rate, %							
	5	6	7	8	10	12	15	20
21	0.07800	0.08500	0.09229	0.09983	0.11562	0.13224	0.15842	0.20444
22	0.07597	0.08305	0.09041	0.09803	0.11401	0.13081	0.15727	0.20369
23	0.07414	0.08128	0.08871	0.09642	0.11257	0.12956	0.15628	0.20307
24	0.07247	0.07968	0.08719	0.09498	0.11130	0.12846	0.15543	0.20255
25	0.07095	0.07823	0.08581	0.09368	0.11017	0.12750	0.15470	0.20212
26	0.06956	0.07690	0.08456	0.09251	0.10916	0.12665	0.15407	0.20176
27	0.06829	0.07570	0.08343	0.09145	0.10826	0.12590	0.15353	0.20147
28	0.06712	0.07459	0.08239	0.09049	0.10745	0.12524	0.15306	0.20122
29	0.06605	0.07358	0.08145	0.08962	0.10673	0.12466	0.15265	0.20102
30	0.06505	0.07265	0.08059	0.08883	0.10608	0.12414	0.15230	0.20085
31	0.06413	0.07179	0.07980	0.08811	0.10550	0.12369	0.15200	0.20070
32	0.06328	0.07100	0.07907	0.08745	0.10497	0.12328	0.15173	0.20059
33	0.06249	0.07027	0.07841	0.08685	0.10450	0.12292	0.15150	0.20049
34	0.06176	0.06960	0.07780	0.08630	0.10407	0.12260	0.15131	0.20041
35	0.06107	0.06897	0.07723	0.08580	0.10369	0.12232	0.15113	0.20034
40	0.05828	0.06646	0.07501	0.08386	0.10226	0.12130	0.15056	0.20014
45	0.05626	0.06480	0.07350	0.08259	0.10139	0.12074	0.15028	0.20005
50	0.05478	0.06344	0.07246	0.08174	0.10086	0.12042	0.15014	0.20002

TABLE 5-3. RECOMMENDED FORMAT FOR PRESENTING CAPITAL COSTS

EQUIPMENT COST	
Basic equipment (includes freight)	
Required auxiliaries	
Total Equipment Cost	
INSTALLATION COSTS, DIRECT	
Foundations and supports	
Duct work (not incl. w/boiler)	
Piping	
Insulation	
Painting	
Electrical	
Buildings	
Total Installation Costs	
TOTAL DIRECT COSTS (Equipment + Installation)	
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	
Construction and field expense (10% of direct costs)	
Construction fees (10% of direct costs)	
Startup (2% of direct costs)	
Performance tests (minimum $2000)	
TOTAL INDIRECT COSTS	
Contingencies (20% of direct and indirect costs)	
TOTAL TURNKEY COSTS (Direct + Indirect + Contingencies)	
Land	
Working capital (25% of total direct operating costs)[a]	
GRAND TOTAL (Turnkey + Land + Working Capital)	

[a] From annual cost table.

TABLE 5-4. RECOMMENDED FORMAT FOR PRESENTING ANNUALIZED COSTS

DIRECT COST	
Direct labor	
Supervision	
Maintenance labor	
Maintenance materials	
Replacement parts	
Electricity	
Steam	
Cooling water	
Process water	
Fuel	
Waste disposal	
Chemicals	
Total Direct Cost	
OVERHEAD	
Payroll (30% of direct labor)	
Plant (26% of labor, parts, and maint.)	
Total Overhead Cost	
Byproduct Cost or Credit	
CAPITAL CHARGES	
G & A, taxes, and insurance (4% of total turnkey costs)	
Capital recovery factor (____%[a] of total turnkey costs)	
Interest on working capital (10% of working capital)	
Total Capital Charges	
TOTAL ANNUALIZED COSTS	

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[a] Calculated from the expected lifetime of the equipment and the annual interest rate.

5.3 UNIT COST RECOMMENDATIONS

To estimate the annual costs of operation and maintenance of boilers and the associated control devices, one must estimate both the quantities of raw materials, utilities, and labor, and also the unit price of each of these items, such as dollars per man-hour for labor. For consistent cost estimation, the same unit prices should be used in all cases. Although these unit prices depend on many factors, geographical location is one of the most significant. As a consistent basis for cost comparison, the Midwest region was selected. The Midwest was chosen because it has a heavy concentration of industry, and thus a large number of industrial boilers.

Unit prices applicable to the Midwest were obtained through review of periodicals giving cost statistics for fuels, labor, chemicals, and utilities. Table 5-5 presents the recommended unit prices for the operation and maintenance items and lists the source of each value.

TABLE 5-5. ANNUAL UNIT COSTS FOR OPERATION AND MAINTENANCE (June 1978 dollars)

Cost factors	Recommended value
Direct labor, $/man-hour	12.02[a]
Supervision, $/man-hour	15.63[b]
Maintenance labor, $/man-hour	14.63[a]
Electricity, mills/kWh	25.8[c]
Untreated water, $\$/10^3$ gal	0.12[d]
Process water, $\$/10^3$ gal	0.15[d]
Cooling water, $\$/10^3$ gal	0.18[e]
Boiler feed water, $\$/10^3$ gal	1.00[f]
Coal, $\$/10^6$ Btu	
Eastern high-sulfur	0.74[g]
Eastern medium-sulfur	0.95[h]
Eastern low-sulfur	1.16[g]
Wyoming low-sulfur	0.42[g]
No. 2 fuel oil, $\$/10^6$ Btu	3.00[i]
No. 6 fuel oil, $\$/10^6$ Btu	2.21[i]
Natural gas, $\$/10^6$ Btu	1.95[j]
Lime (bulk, delivered), $/ton	35.00[k,l]
Limestone (bulk, delivered), $/ton	8.00[k,m]
Sodium hydroxide (bulk, 50% basis, f.o.b. works), $/ton	158.00[k]
Sodium carbonate (bulk, delivered), $/ton	90.00[k,n]
Ammonia (delivered), $/ton	130.00[k]
Ammonium hydroxide (29.3% NH_3 basis, freight equalized), $/ton	173.00[k]

[a] Engineering News-Record, June 29, 1978, pp. 52-52. Average for Chicago, Cincinnati, Cleveland, Detroit, and St. Louis.

[b] Estimated at 30 percent over direct labor rate.

[c] EEI members publication for June, 1978. Average for Boston, Chicago, Indianapolis, Houston, San Francisco, and Los Angeles.

[d] Peters, M.S., and K.D. Timmerhaus. Plant Design and Economics for Chemical Engineers, 2nd Edition. McGraw-Hill Book Co. New York 1968. p. 772. Adjusted to 1978 prices using Nelson Refinery Operating Cost Indexes for Chemicals. July 1978.

[e] Perry J.H., et al. Chemical Engineer's Handbook. McGraw-Hill Book Co. New York, 1963, pp. 26-29.

[f] Nelson, W.L. Guide to Refinery Operating Costs. The Petroleum Publishing Company, 1966, p. 27.

[g] Coal Outlook, July 18, 1978. Spot market prices.

[h] Average of prices for high- and low-sulfur coal.

[i] Electrical Week, May issues, 1978. Spot market prices.

[j] Gas Facts, 1977. American Gas Association. Average U.S. price.

[k] Chemical Marketing Reporter, June 19, 1978. F.o.b. cost.

[l] Value includes assumed delivery cost of $3.00/ton.

[m] Value includes assumed delivery cost of $2.00/ton.

[n] Value includes assumed delivery cost of $30.00/ton.

SOURCES OF TYPICAL VALUES LISTED IN TABLE 5-1

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SECTION 6

COST ESTIMATES FOR NEW BOILERS

As a basis for comparative evaluation of various pollution control techniques and their annualized costs, estimates were developed for the cost of new installations of each of the typical boilers described earlier. An outline of the procedures used in developing the costs is followed by the cost estimates.

6.1 COST ESTIMATING PROCEDURE

Cost of a boiler facility includes the costs of basic equipment, the costs of installation, and the costs of operating and maintaining the boiler. In accordance with the procedure described in Section 5, a capital cost estimate is developed by the following steps:

- Define the battery limits of the facility.
- Develop a list of equipment required.
- Obtain prices for each equipment item.
- Calculate installation costs.
- Calculate indirect capital costs.

Costs are all-inclusive, accounting for the material and labor needed to complete an operational boiler plant. The estimates were prepared from a detailed equipment summary. Estimates of erection costs are based on experience and on actual cost of erection at similar plants.

Battery limits of the facility extend as from the fuel-receiving equipment to the ash disposal operation, inclusively. Excluded are steam and condensate piping beyond the boiler building and pollution control equipment. Costs of ducting and the stack are included.

Based on guidelines presented by H.K. Ferguson (Coffin, 1978), an equipment list was developed for each boiler. The major equipment items are described below.

Water enters the system through a treatment process--for this study a standard Zeolite softening system. The makeup water is then fed to a deaerator, which has a 15-minute holding capacity at full flow. The return condensate is piped to the condensate return tank. It is assumed that 20 percent makeup is required. The overflow storage tank for the condensate return tank is sized to hold the condensate generated in 1 hour at full load capacity.

A continuous-blowdown flash tank and drain heat recovery system recover all available heat from both the flash steam and the drains.

Two boiler feed pumps are provided, 100 percent capacity each. Automatic recirculation shutoff is not included. A fixed minimum-flow bypass orifice is used for simplicity.

Each oil-fired boiler has 100 percent Maximum Capacity Rating (MCR) oil-burning capability and includes a storage tank and transfer pump facility. In the plant, a pump and heater set are provided, consisting of two pumps (100 percent capacity) for firing of No. 6 oil. Capacity of the storage tank provides approximately 7 days firing at MCR.

Coal is stored in the plant in overhead bunkers supported by the building steel. Coal is loaded into the bunkers by a conveying system designed to fill the bunkers completely during an 8-hour shift. Bunker capacity is sufficient to operate the plant for 24 hours at full load.

The conveying system includes the under-track hopper, which supplies a coal silo with 10 days' storage; a bucket elevator or belt conveyor, depending on building height (100 ft maximum for a bucket elevator); and an over-bunker tripper conveyor to load each bunker section. A crusher included with the hopper allows some sizing of the coal feed.

The stoker-fired plants include an under-bunker conveyor, tripper mechanism, and a nonsegregating conical distributor to the stoker hopper.

The pulverized-coal-fired plant includes gravimetric feeders to the pulverizers.

Ash handling systems of the pneumatic type (dry) transport fly ash and bottom ash to a temporary storage silo for later removal by truck. The bottom ash handling equipment includes a clinker breaker.

Except for the pulverized-coal-fired boiler, which requires an air heater to dry the coal sufficiently, all boilers are equipped with economizers.

Controls are provided to regulate combustion, feedwater, and flame safety. The pulverized-coal-fired boiler also has an electronic pulverizer control system for safe and reliable starting of the pulverizers.

The building, constructed of insulated steel, includes a small office area and employees' washroom. No provision is made for an enclosed control room for the operators; rather, the boiler control panels are free-standing in front of the boiler firing aisle. Lighting, ventilation, ladders, gratings, and painting are included.

A 4047- to 8094-m^2 (1- to 2-acre) parcel of land is allocated to each boiler, depending on the boiler size. Table 6-1 lists the basic equipment and installation items included in the capital cost estimates. Table 6-2 lists the sources of data used in estimating capital costs. Costs were obtained for the low-sulfur bituminous coal; costs were then apportioned to the subbituminous and high-sulfur bituminous coals by use of factors obtained from boiler manufacturers. Indirect capital costs were estimated according to guidelines in Section 5.

The costs are based on a Greenfield boiler installation with no pollution control equipment, located in the Midwest. Regional cost factors may be used to estimate costs in areas other than the Midwest.

TABLE 6-1. BASIC EQUIPMENT AND INSTALLATION ITEMS INCLUDED IN A NEW BOILER FACILITY

Equipment:

- Boiler (with fans and ducts)
- Stack
- Instrumentation
- Pulverizers or Stoker system
- Feeders
- Crushers
- Deaerator
- Heaters
- Boiler feed pumps
- Condensate systems
- Water treating system
- Chemical feed
- Compressed air system
- Coal handling system
- Ash disposal system
- Thawing equipment
- Fuel oil system

Installations:

- Foundations and supports
- Piping
- Insulation
- Painting
- Electrical
- Building

TABLE 6-2. SOURCES OF COST DATA FOR EQUIPMENT AND INSTALLATION ITEMS INCLUDED IN BOILER PLANTS

Equipment item	Sources of cost data
Boiler (with fans and ducts)	Babcock & Wilcox Co. Combustion Engineering, Inc. Cleaver-Brooks Division of Aqua-Chem Erie City Energy Division of Zurn E. Keeler Co.
Stacks	Airtek Rust Engineering Richardson Cost Estimating Manual[a]
Instrumentation	Aedes Associates, Inc. Babcock & Wilcox Co. Combustion Engineering, Inc. Cleaver-Brooks Division of Aqua-Chem Erie City Energy Division of Zurn E. Keeler Co.
Pulverizers or stoker system	Babcock & Wilcox Co. Combustion Engineering, Inc. Cleaver-Brooks Division of Aqua-Chem Erie City Energy Division of Zurn E. Keller Co.
Feeders	Jeffrey Manufacturing Co. Babcock & Wilcox Co. Combustion Engineering, Inc. Cleaver-Brooks Division of Aqua-Chem Erie City Energy Division of Zurn E. Keeler Co.
Crushers	Pennsylvania Crusher Co. Richardson Cost Estimating Manual[a]
Deaerator	Chicago Heater Co. Cochrane Environmental Systems
Heaters	Richardson Cost Esimating Manual
Boiler feed pumps	Ingersoll-Rand Richardson Cost Estimating Manual[a] Richardson Cost Estimating Manual[a]

(continued)

TABLE 6-2 (continued)

Equipment items	Sources of cost data
Condensate system	Richardson Cost Estimating Manual[a]
Water treatment system	Crane Cochran Zeolite Calgon Corp.
Chemical feed	Milton Roy Co. Richardson Cost Estimating Manual[a]
Compressed air system	Ingersoll-Rand Richardson Cost Estimating Manual[a]
Coal handling system	Jeffrey Manufacturing Co. Caterpillar Co. Richardson Cost Estimating Manual[a]
Ash disposal system	Allen-Sherman-Hoff, Inc. United Conveyor Richardson Cost Estimating Manual[a]
Thawing equipment	Aedes Associates, Inc.
Fuel oil system	Coen Co. Aedes Associates, Inc.
Foundations and supports	Aedes Associates, Inc.
Piping	Aedes Associates, Inc.
Insulation	Aedes Associates, Inc.
Painting	Aedes Associates, Inc.
Electrical	Aedes Associates, Inc.
Building	Aedes Associates, Inc.

[a] Richardson, 1978.

Given equipment costs and installation costs, the indirect capital costs such as engineering and contractor's fee were calculated according to the guidelines in Section 5.

Table 6-3 lists the elements of annual operating and maintenance costs; Table 6-4 indicates the methods used in developing the costs; Table 6-5 shows the manpower requirements on which the labor costs are based. Annual overhead charges are estimated in accordance with Section 5 guidelines, as are capital-related charges.

The cost of disposing of bottom ash from a coal-fired boiler is based on a 32-km (20-mi) one-way haul to ultimate disposal in an environmentally sound landfill. The bottom ash is assumed to be wetted to 20 percent moisture and hauled in covered trucks. The disposal cost components include truck loading, washing the loaded trucks, truck transportation, road cleaning and repair, truck unloading, washing the unloaded trucks, and landfill fees, including treatment. The ash disposal operation is conducted by an outside contracting firm rather than the company itself. The waste disposal cost is estimated at $44/Mg ($40/ton). This is a conservative estimate of the average cost for a typical industrial boiler with a heat input of about 30 MW thermal (100 x 10^6 Btu/h). Although the waste disposal cost can vary greatly depending upon the haul distance and the method of disposal, this conservative estimate reflects good environmental practice.

Annual operating and maintenance costs are based on requirements for labor, materials, and utilities as cited by manufacturers of boilers and auxiliary equipment, together with the unit costs specified for the Midwest in Table 5-5.

Capital recovery factors are based on the following boiler life expectancies:

Boiler type	Expected life, years
Package Scotch fire-tube	20
Package water-tube	30
Field-erected water-tube	45

TABLE 6-3. DIRECT ANNUAL OPERATION AND MAINTENANCE COST ITEMS ASSOCIATED WITH BOILERS

Operational labor
Supervision
Maintenance labor
Replacement labor
Electricity
Process water
Fuel
Waste disposal
Chemicals

TABLE 6-4. METHODS USED TO ESTIMATE DIRECT ANNUAL COSTS

Cost item	Method of obtaining cost
Operational labor	Multiply manpower requirements from Table 6-5 by rate given in Table 5-5.
Supervision	Multiply manpower requirements from Table 6-5 by rate given in Table 5-5.
Maintenance labor	Multiply manpower requirements from Table 6-5 by rate given in Table 5-5.
Replacement parts	Aedes Associates, Inc., determined percentages of total equipment cost based on actual jobs (8 to 21%).
Electricity	Based on major equipment and lighting loads.
Oil or gas-fired boilers	114 to 379 kW
Stoker units	250 to 773 kW
Pulverized-coal-fired units	1700 to 5100 kW
	Multiply kW by operating hours to obtain annual kWh. Multiply annual kWh by electric rate given in Table 5-5.
Process water	Requirement calculated assuming 80 percent return of condensate (20% make-up). Multiply annual usage by water rate given in Table 5-5.
Fuel	Fuel requirement calculated based on design heat input multipled by hours per year operated based on load factors given in Tables 4-2 to 4-11. Multiply annual fuel requirement by appropriate rate from Table 5-5.
Waste disposal	Requirement calculated from total ash in fuel minus the quantity emitted as fly ash. Multiply the annual quantity of waste by an average cost of \$44/Mg (\$40/ton) for disposal in an environmentally sound landfill 32 km (20 mi) from the plant site.
Chemicals	Requirement calculated assuming constant water quality and 80 percent return of condensate (20% make-up). Multiply amount of chemicals used by average costs obtained from chemical suppliers.

TABLE 6-5. SUMMARY OF THE MANPOWER REQUIREMENTS FOR THE SELECTED REPRESENTATIVE BOILERS
(man-years)

Boiler type	Direct labor	Supervision	Maintenance labor
Heat input, 4.4 MW thermal (15×10^6 Btu/h)			
Natural-gas-fired	4	2	1
Oil-fired	4	2	1
Heat input, 8.8 MW thermal (30×10^6 Btu/h)			
Oil-fired	4	2	1
Coal-fired	6	2	2
Heat input, 22.0 MW thermal (75×10^6 Btu/h)			
Coal-fired	8	4	4
Heat input, 44 MW thermal (150×10^6 Btu/h)			
Natural-gas-fired	8	2	2
Oil-fired	8	2	2
Coal-fired	12	4	4
Heat input, 58.6 MW thermal (200×10^6 Btu/h)			
Coal-fired	16	4	6
Heat input, 117.2 MW thermal (400×10^6 Btu/h)			
Coal-fired	28	6	12

From these values for boiler life and the assumed interest rate of 10 percent (Section 5), the capital recovery factors calculated for each boiler type are as follows:

Boiler type	Capital recovery factor, %
Package Scotch fire-tube	11.75
Package water-tube	10.61
Field-erected water-tube	10.14

6.2 COST ESTIMATES

Costs are estimated for each of the typical boilers identified in Section 4. The basic boiler costs were obtained as verbal or written quotations from various boiler manufacturers including Babcock and Wilcox; Cleaver Brooks; Zurn Industries, Inc.; Erie City; and Combustion Engineering. Capital cost estimates for auxiliary equipment (e.g., water treatment systems) are based on quotations obtained from manufacturers in related projects.

Table 6-6 summarizes the estimated capital and annualized costs for the representative boilers. Details of the cost estimates for each combination of representative boiler and fuel type are presented in Appendix G.

The estimated costs for new boilers vary widely. The total capital costs of the boilers considered in this study range from $389,800 for a package fire-tube boiler firing natural gas with a heat input of 4.4 MW thermal (15×10^6 Btu/h) to $26,836,600 for a field-erected water-tube boiler firing pulverized subbituminous coal with a heat input of 117.2 MW thermal (400×10^6 Btu/h). The major factors influencing cost are boiler size and fuel. Coal-fired boilers are generally more expensive to build than gas- or oil-fired boilers because of the need for larger furnaces and more elaborate fuel handling equipment, but are cheaper to operate because of lower fuel prices.

TABLE 6-6. ESTIMATED CAPITAL AND ANNUALIZED COSTS FOR THE SELECTED REPRESENTATIVE BOILERS

Boiler type	Fuel	Boiler capacity, MW thermal (10^6 Btu/h)	Capital cost, $	Annual O and M, $	Fixed cost, $	Total annualized cost, $
Package, fire-tube	Natural gas	4.4 (15)	389,800	439,900	56,100	496,000
Package, fire-tube	Distillate oil	4.4 (15)	405,100	501,000	57,600	558,600
Package, water-tube	Residual oil	8.8 (30)	797,800	678,800	109,600	788,400
Package, water-tube underfeed-stoker	Eastern low-sulfur coal	8.8 (30)	1,665,200	721,600	236,300	957,900
Package, water-tube underfeed-stoker	Eastern high-sulfur coal	8.8 (30)	1,891,300	682,500	269,800	952,300
Package, water-tube underfeed-stoker	Subbituminous coal	8.8 (30)	2,257,100	653,300	323,600	976,900
Field-erected, water-tube, chain-grate-stoker	Eastern low-sulfur coal	22.0 (75)	4,067,900	1,330,500	563,400	1,893,900
Field-erected, water-tube, chain-grate-stoker	Eastern medium-sulfur coal	22.0 (75)	4,165,300	1,283,900	577,600	1,861,500
Field-erected, water-tube, chain-grate-stoker	Eastern high-sulfur coal	22.0 (75)	4,554,400	1,217,900	633,300	1,851,200
Field-erected, water-tube, chain-grate-stoker	Subbituminous coal	22.0 (75)	5,341,000	1,120,100	745,700	1,865,800
Package, water-tube	Natural gas	44.0 (150)	2,118,700	2,035,100	287,800	2,322,900

(continued)

TABLE 6-6 (continued)

Boiler type	Fuel	Boiler capacity, MW thermal (10^6 Btu/h)	Capital cost, $	Annual O and M, $	Fixed cost, $	Total annualized cost, $
Package, water-tube	Residual oil	44.0 (150)	2,244,900	2,223,100	304,100	2,527,200
Package, water-tube	Distillate oil	44.0 (150)	2,379,700	2,793,900	317,100	3,111,000
Field-erected, water-tube, spreader-stoker	Eastern low-sulfur coal	44.0 (150)	7,804,100	2,101,800	1,084,500	3,186,300
Field-erected, water-tube, spreader-stoker	Eastern high-sulfur coal	44.0 (150)	8,784,200	1,849,100	1,225,900	3,075,000
Field-erected, water-tube, spreader-stoker	Subbituminous coal	44.0 (150)	10,395,800	1,665,400	1,455,800	3,121,100
Field-erected, water-tube, pulverized-coal	Eastern low-sulfur coal	58.6 (200)	10,823,200	2,875,600	1,504,400	4,380,000
Field-erected, water-tube, pulverized-coal	Eastern high-sulfur coal	58.6 (200)	12,202,400	2,544,800	1,702,900	4,247,700
Field-erected, water-tube, pulverized-coal	Subbituminous coal	58.6 (200)	14,468,400	2,343,000	2,025,600	4,368,600
Field-erected, water-tube, pulverized-coal	Eastern low-sulfur coal	117.2 (400)	20,094,000	5,317,000	2,792,500	8,109,500
Field-erected, water-tube, pulverized-coal	Eastern medium-sulfur coal	117.2 (400)	20,707,300	4,957,700	2,883,000	7,840,700
Field-erected, water-tube, pulverized-coal	Eastern high-sulfur coal	117.2 (400)	22,638,000	4,624,100	3,159,500	7,783,600
Field-erected, water-tube, pulverized-coal	Subbituminous coal	117.2 (400)	26,836,600	4,171,800	3,758,200	7,930,000

Another factor that strongly affects costs is the method of boiler construction. Field-erected boilers are much more expensive than package boilers because construction is more complex.

The major factor affecting annual operating and maintenance costs is the price of the fuel. Total fixed annual costs are directly proportional to the turnkey cost of the boilers and are in the range of 10 to 40 percent of total annualized costs.

REFERENCES FOR SECTION 6

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Richardson Engineering Services, Inc. 1978. Process Plant Construction Estimating and Engineering Standards. Solana Beach, California.

APPENDIX A

DETAILED BOILER DESCRIPTIONS

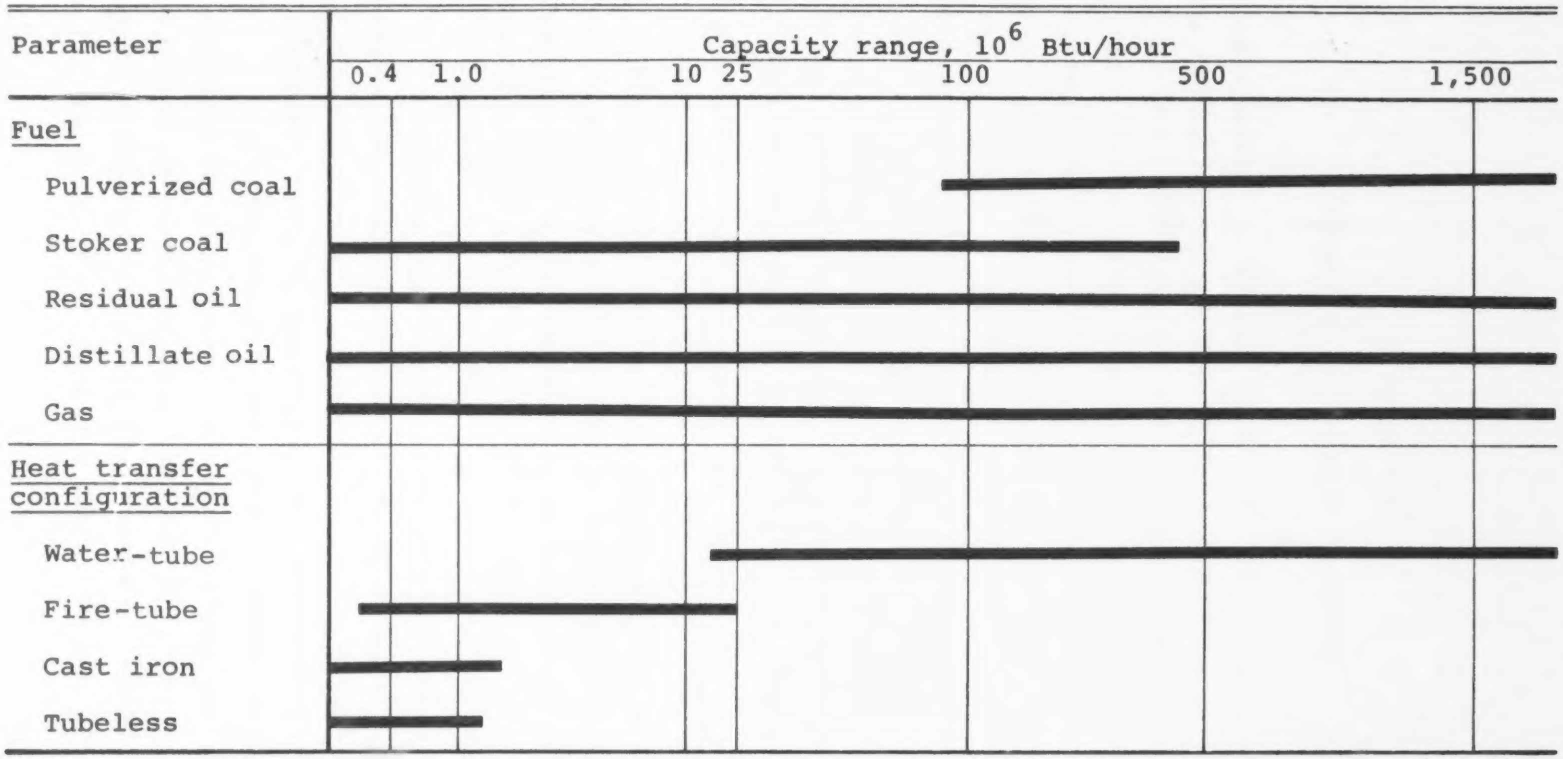
There are three major types of boilers: water-tube, fire-tube, and cast iron. Each type of boiler is suited to specific applications and sites. Water-tube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat for industrial and commercial facilities. Fire-tube boilers are not available with capacities as large as those of water-tube boilers, but they also are used in a variety of applications, such as to supply process steam and for space heating. Cast iron boilers are limited in size and are used only to supply space heat. Figure A-1 illustrates the occurence of various important parameters in different sizes of boilers. Following are detailed discussions of each boiler type.

WATER-TUBE BOILERS

A water-tube boiler is one in which the hot combustion gases resulting from combustion of fuel are in contact with the outside of the heat transfer tubes while the boiler water and steam contact the inside of the tubes. The tubes are interconnected to common water channels and to a steam outlet or outlets. Figure A-2 is a simplified diagram of a water-tube boiler.

Water-tube boilers generate high-pressure, high-temperature steam. The boilers are available in many sizes; the tubes are of relatively small diameter, providing rapid heat transfer, good response to steam demands, and high efficiency.

Used in a variety of utility, industrial, and commercial applications, water-tube boilers are available as packaged or field-erected units. Capacity of the packaged units ranges from 4,540 kg (10,000 lb) of steam per hour to as high as 113,000 kg



(continued)

Figure A-1. Occurrence of various boiler parameters by capacity range.

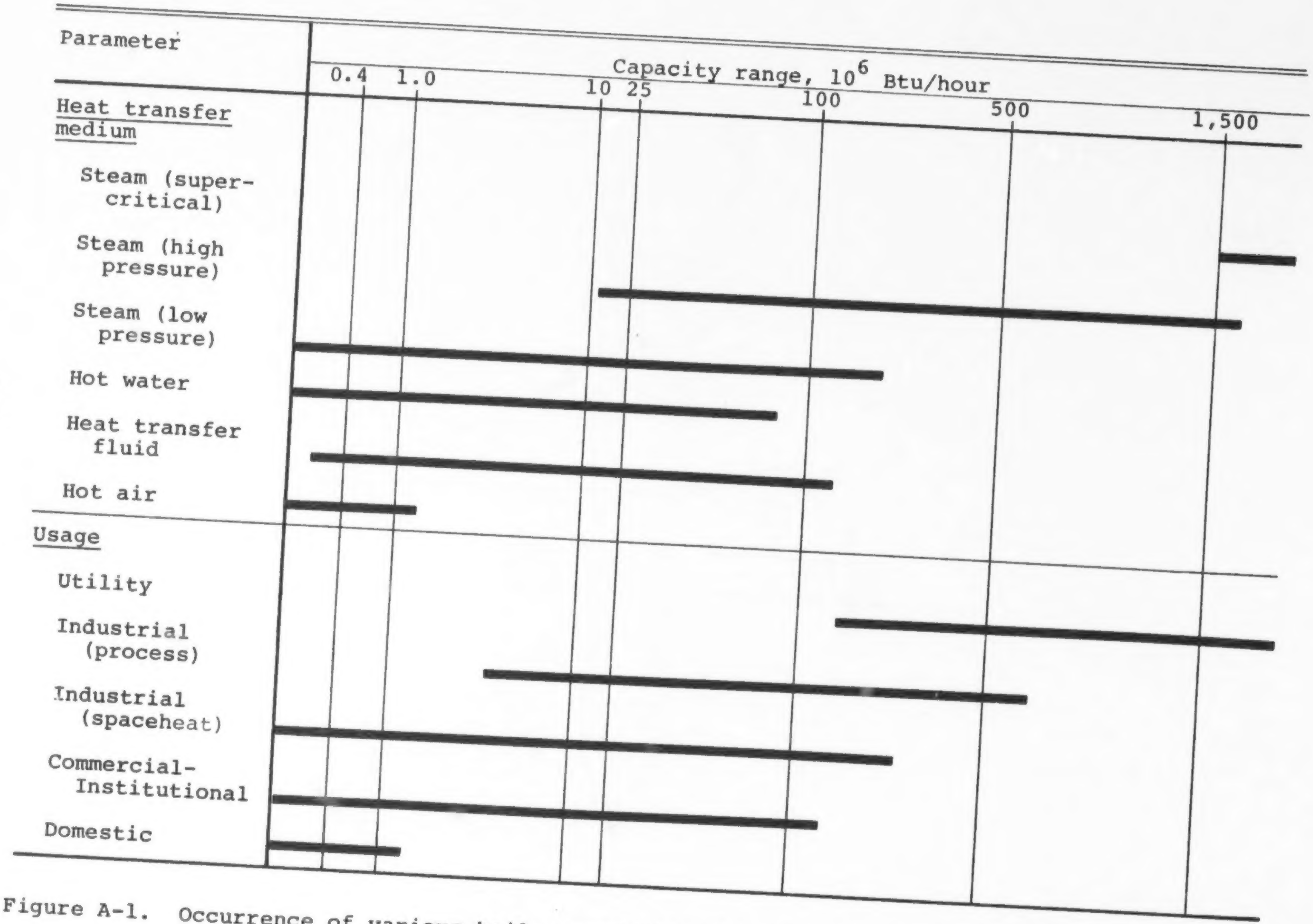


Figure A-1. Occurrence of various boiler parameters by capacity range (continued).

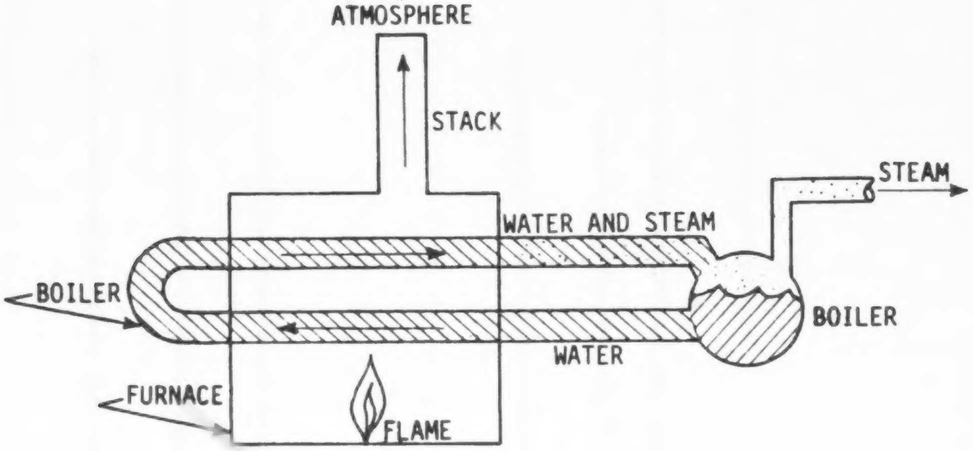

TO ATMOSPHERE
STACK
STEAM
WATER AND STEAM
BOILER
BOILER
WATER
FURNACE
FLAME

Figure A-2. Simplified diagram of a water-tube boiler.

(250,000 lb) of steam per hour. Units of higher capacity are field-erected.

Water-tube boilers can burn any economically available fuel very efficiently. They are available in a variety of designs and configurations to fit any plant capacity and space requirement. Major types of water-tube boilers are vertical, vertically inclined, and horizontal (and combinations of these). These classifications refer to the orientation of the tubes within the furnace. All water-tube boilers are characterized by the interconnection of tube sections, headers, and drums.

Water-tube boilers are also classified as units with natural or forced circulation. Natural circulation results from the difference in water and steam density. Forced circulation is achieved with pumps that circulate water and steam through the boiler. These units do not include drums because water is not recirculated through the boiler and separation of the steam and water is unnecessary. Forced circulation boilers can operate in the supercritical range at capacities exceeding 4,536 Mg (10,000,000 lb) of steam per hour.

Coal-fired water-tube boilers consist of two main types: stoker-fired and pulverized-coal-fired.

A stoker is a conveying system that feeds coal into a furnace and also provides a moving grate upon which the coal is burned. The feed rates to stoker furnaces are limited; stokers are generally used on units rated at less than 176 MW thermal (600 x 10^6 Btu/h) heat input. The following paragraphs describe the three main types of stoker furnaces: underfeed, overfeed, and spreader.

Underfeed Retort Stokers

Various underfeed retort stokers are available, depending on whether the coal is fed horizontally or by gravity, whether the ash is discharged from the end or the sides, and the number of retorts.

Single- or double-retort units can be designed in sizes up to 120 megawatts thermal (400 million Btu/h) heat input. Multiple-retort gravity-fed stokers can be designed to generate up to 180 Mg (400,000 lb) of steam per hour.

In the side-discharge, horizontal underfeed stoker, shown in Figure A-3, coal is fed intermittently to the fuel bed by a ram or, in very small units, is fed continuously by a screw. The coal moves in a longitudinal channel, called a retort, and air is supplied through tuyeres on each side and through openings in the side grates.

Overfire air is commonly used with underfeed stokers to provide some combustion air and turbulence in the flame zone directly above the active fuel bed. The air is provided by a separate overfire-air fan and is injected through small nozzles in the furnace walls.

An underfeed stoker can burn a wide range of coals, including coking coals and anthracite, but it is best suited for bituminous coals. The size of the coal directly affects the capacity and efficiency of the underfeed stoker. The most desirable size consists of pieces 3.2 cm (1-1/4 in.) and smaller, with not more than 50 percent fines that will pass through a 0.6-cm (1/4-in.) screen.

Overfeed (Chain-Grate or Moving-Grate) Stokers

Moving-grate stokers are classified as overfeed stokers. They are equipped with chain or moving grates and with refractory arches or overfire-air jets to improve combustion. This type of stoker is usually designed for forced draft; natural draft designs are gradually becoming obsolete.

Chain-grate and moving-grate stokers can produce up to 140 Mg (300,000 lb) of steam per hour. A continuous fuel burning rate of 5700 MJ/m^2 (500,000 Btu/ft^2) of grate per hour can be achieved.

In chain-grate and traveling-grate stokers, assembled links of grates are joined in an endless belt that passes over sprockets or return bends located at the front and rear of the furnace. As

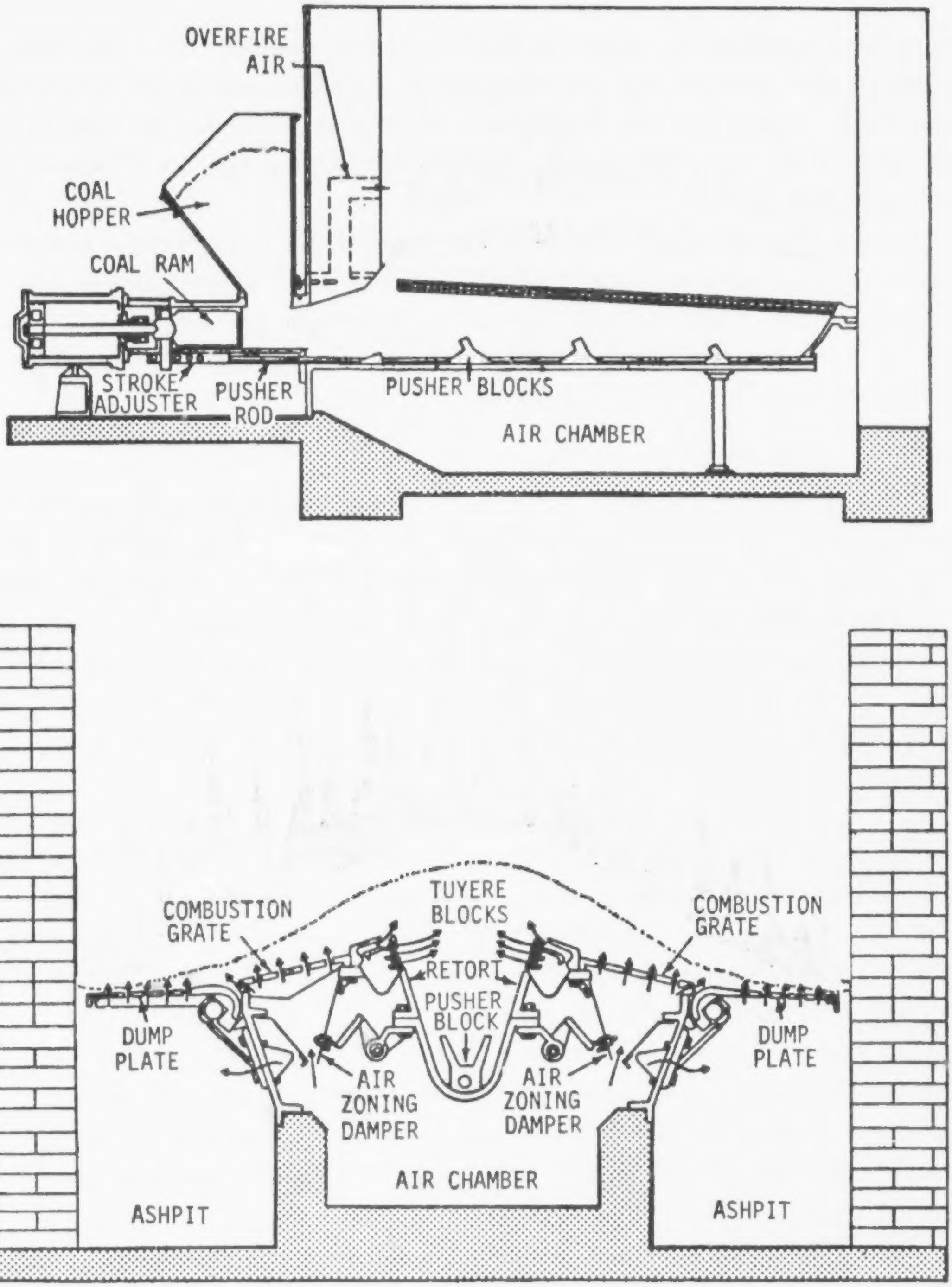

OVERFIRE AIR
COAL HOPPER
COAL RAM
STROKE ADJUSTER
PUSHER ROD
PUSHER BLOCKS
AIR CHAMBER
COMBUSTION GRATE
TUYERE BLOCKS
COMBUSTION GRATE
RETORT
PUSHER BLOCK
DUMP PLATE
AIR ZONING DAMPER
AIR ZONING DAMPER
DUMP PLATE
AIR CHAMBER
ASHPIT
ASHPIT

Figure A-3. Single-retort, horizontal underfeed stoker with side ash discharge.

shown in Figure A-4, coal is fed from the hopper onto the moving assembly and enters the furnace after passing under an adjustable gate that regulates the thickness of the fuel bed. At the far end of the grate, combustion is completed and ash is discharged into the ashpit.

Most stoker-fired furnaces are provided with water cooling. Completely water-cooled furnaces require less maintenance and form less slag than refractory or air-cooled furnaces.

The chain-grate and traveling-grate stoker can be designed to burn all kinds of solid fuels.

Spreader Stokers

The spreader stoker combines suspension burning and a thin, fast-burning fuel bed on a grate. Capacities of spreader stokers range from 2.3 to 180 Mg (5000 to 400,000 lb) of steam per hour.

The modern spreader stoker, as shown in Figure A-5, consists of feeder units (arranged to distribute fuel over the grate area), a grate, forced-draft systems for both undergrate and overgrate air, and combustion controls to coordinate air and fuel supply.

An integral part of many spreader-stoker firing systems is the provision for fly ash recirculation, wherein the fly ash that is removed from the flue gas stream is reinjected into the furnace. A gravity-flow fly ash return is shown in Figure A-6. Pneumatic conveying systems are used for reinjection in the high temperature zone above the grate.

Traveling-grate spreader stokers are generally installed with one large plenum or air chamber under the entire grate surface. Overfire-air systems are useful in promoting good combustion and reducing the formation of smoke, especially at low loads.

Spreader stokers are versatile and can be designed to burn almost any type of solid fuel. Free-burning bituminous and lignite coals are commonly used, and other fuels such as bagasse (sugar cane refuse) and wood waste are also satisfactory.

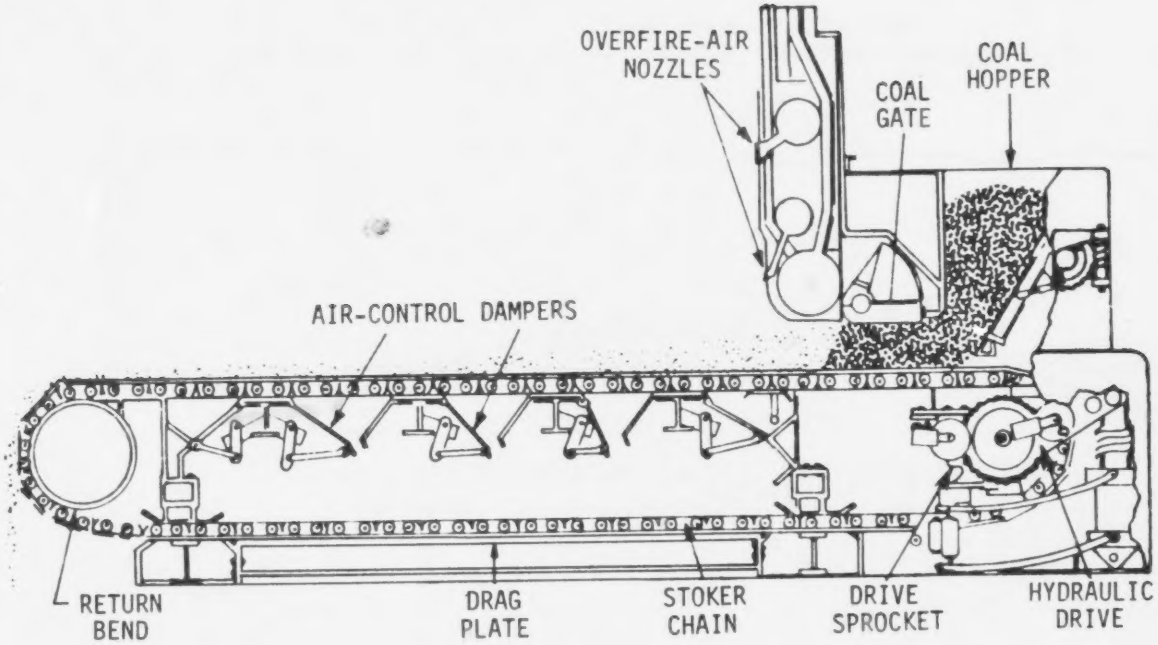

OVERFIRE-AIR
NOZZLES
COAL
GATE
COAL
HOPPER
AIR-CONTROL DAMPERS
RETURN
BEND
DRAG
PLATE
STOKER
CHAIN
DRIVE
SPROCKET
HYDRAULIC
DRIVE

Figure A-4. Chain-grate stoker with rear ash discharge.

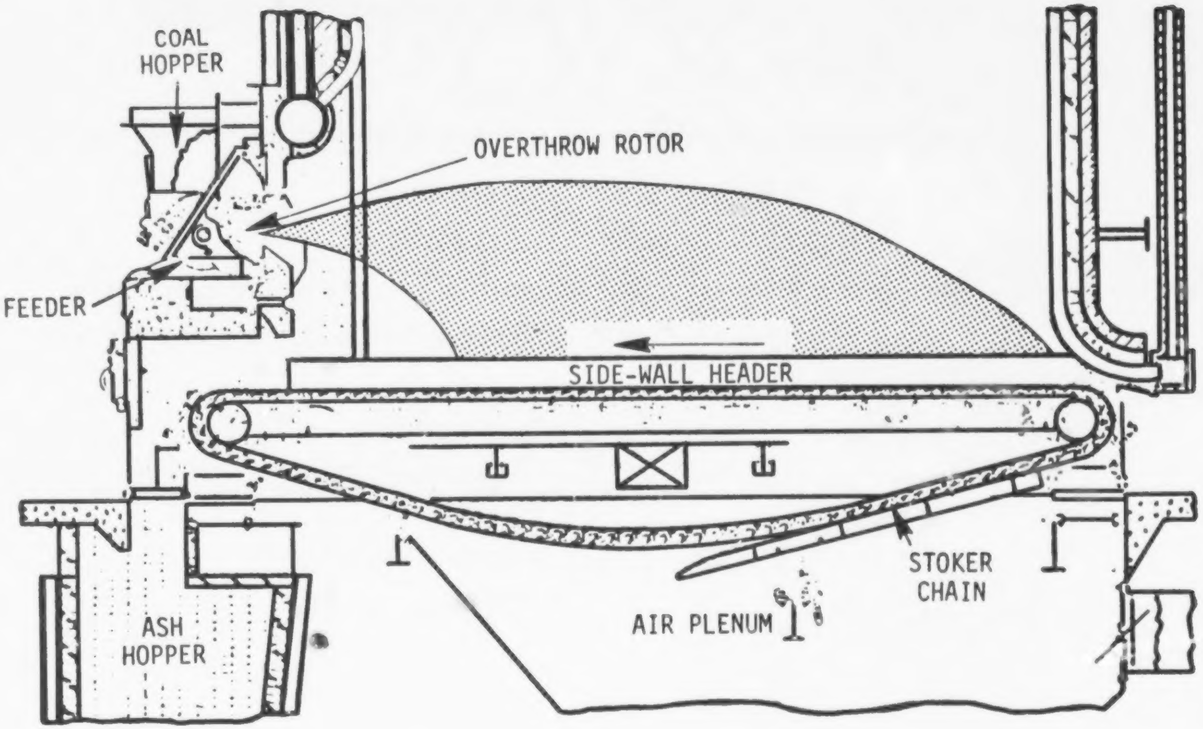

COAL HOPPER
OVERTHROW ROTOR
FEEDER
SIDE-WALL HEADER
ASH HOPPER
AIR PLENUM
STOKER CHAIN

Figure A-5. Traveling-grate spreader stoker with front ash discharge.

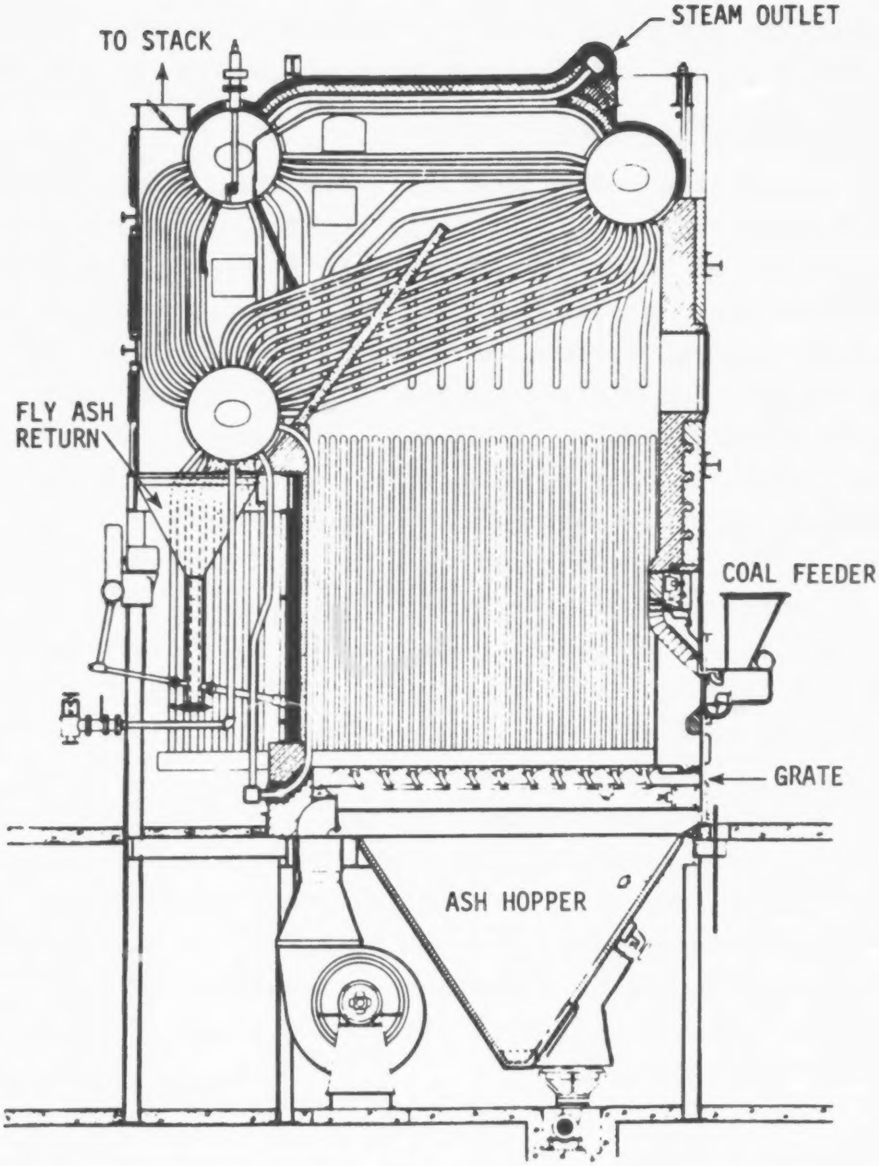

STEAM OUTLET
TO STACK
FLY ASH RETURN
COAL FEEDER
GRATE
ASH HOPPER

Figure A-6. Spreader stoker with gravity-flow fly ash return.
(Courtesy of Babcock & Wilcox)

Anthracite generally is not satisfactory because it is a low-volatility fuel and does not burn adequately in suspension.

Pulverized-Coal-Fired Units

Pulverized-coal-fired units operate on the principle of suspension burning. Coal is pulverized to the consistency of talcum powder and injected into the furnace pneumatically. These furnaces are classified as dry-bottom or wet-bottom, depending on whether the ash is removed in the solid or molten state. Figure A-7 illustrates a direct-fired pulverized-coal unit. In the direct-firing system, hot primary air is ducted to the pulverizer, where the raw coal is dried and pulverized and then is conveyed to the burners in a continuous pattern. The coal is mixed with primary air before entering the burner.

Another pulverized-coal-firing system is the now outdated bin system. The coal is processed at a location apart from the furnace. It is dried, pulverized, classified within the pulverizer, and then stored. From storage, the pulverized coal is conveyed pneumatically to utilization bins. This system was used extensively before reliable pulverizers were developed, but has essentially been replaced by the direct-firing system.

The maximum capacity of individual burners used in pulverized-coal-fired boilers is 48 MW thermal (165 x 10^6 Btu/h). As many as 70 burners may be used, although 16 to 30 burners is more common. The circular type of burner, shown in Figure A-8, is most frequently used.

FIRE-TUBE BOILERS

In fire-tube boilers the products of combustion flow through a tube that is surrounded by a water basin. Figure A-9 is a simplified diagram of a fire-tube boiler. These units are small [up to 5.9 MW thermal (20 x 10^6 Btu/h)] and are used primarily for heating systems, industrial process steam, and portable power boilers. Fire-tube boilers are generally used where loads are relatively constant because they are susceptible to structural

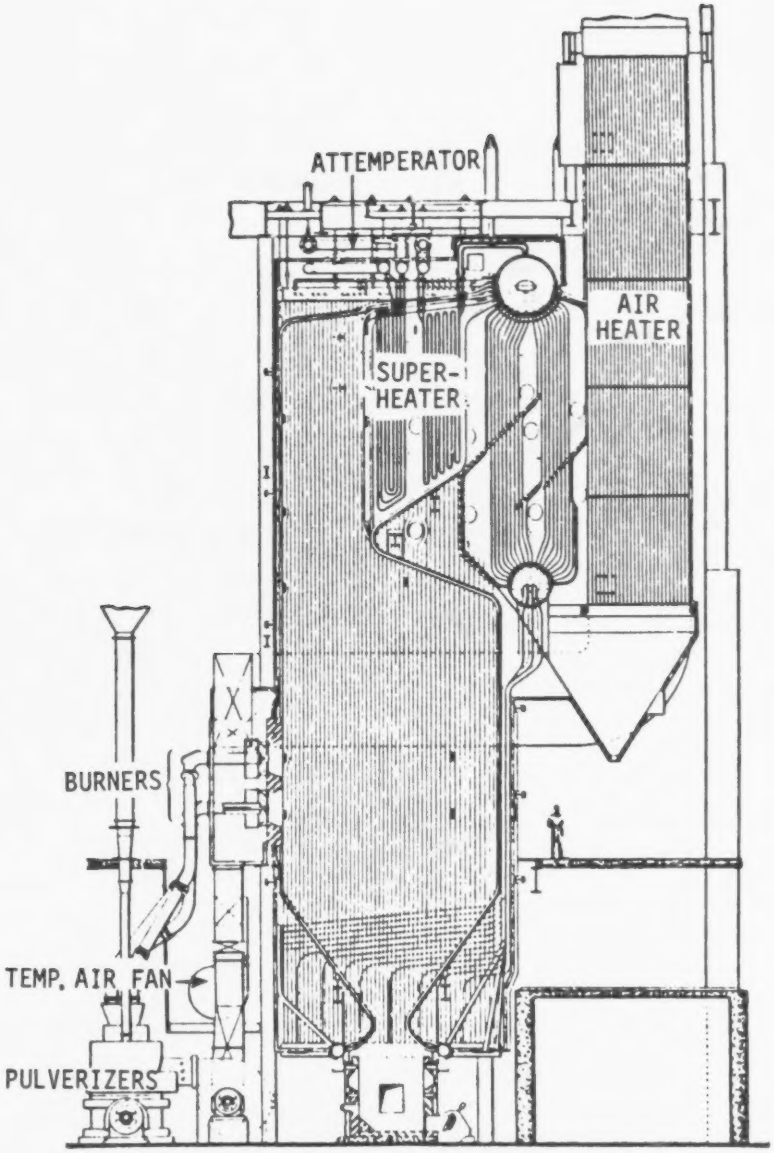

ATTEMPERATOR
AIR HEATER
SUPER-HEATER
BURNERS
TEMP. AIR FAN
PULVERIZERS

Figure A-7. Dry-bottom pulverized-coal-fired unit.
(Courtesy of Babcock & Wilcox)

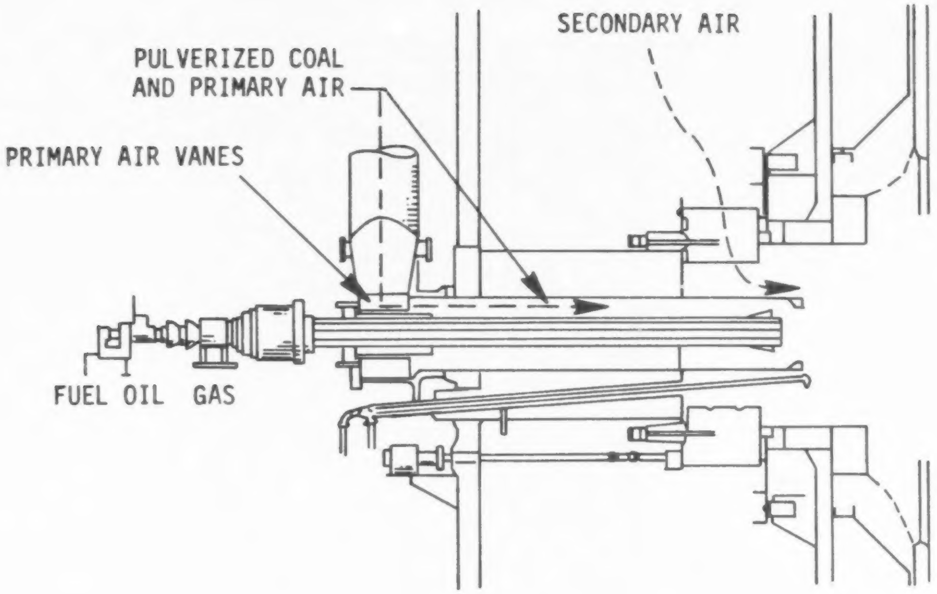

SECONDARY AIR
PULVERIZED COAL AND PRIMARY AIR
PRIMARY AIR VANES
FUEL OIL
GAS

Figure A-8. Circular burners for firing pulverized coal.

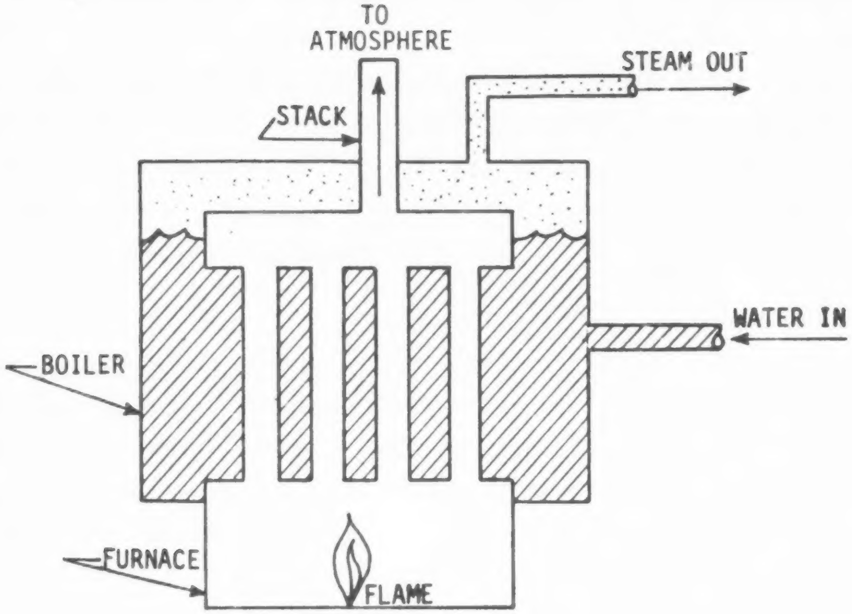

TO ATMOSPHERE
STEAM OUT
STACK
WATER IN
BOILER
FURNACE
FLAME

Figure A-9. Simplified diagram of a fire-tube boiler.

failure when subjected to large variations in steam demand. These units produce steam more efficiently than a simple shell boiler because the water basin absorbs heat through the shell and also through the tubes.

Most of the fire-tube boilers currently installed have internal furnaces; that is, the combustion chamber is enclosed in the boiler shell. In an external furnace arrangement, the boiler shell and combustion chamber are separate. Internal furnaces are preferred because of better water circulation and easier ash removal.

There are six possible configurations in the fire-tube boiler class: horizontal return tubular (HRT), Scotch marine, vertical, locomotive, short firebox, and compact boilers. The three most common configurations are the HRT, Scotch marine, and vertical units. All six are discussed in the following sections.

Horizontal Return Tubular (HRT)

In an HRT boiler the fire-tubes are horizontal to the ground The fuel firing mechanism is at one end, and the products of combustion make two, three, or four passes through the water medium. The furnace is set on rollers or suspended on hangers to allow for expansion and contraction. The boiler is encased with brick and is sloped 2.5 to 7.5 cm (1 to 3 in.) from front to rear (Woodruff and Lammers, 1977). These boilers are well suited for industrial use because they are compact and automatic and the initial cost is low.

In a two-pass boiler, the furnace is at the bottom corner of the unit, as shown in Figure A-10. The products of combustion flow over the bridge wall to the other end of the boiler. As the flue gas passes under the boiler, it heats the outer shell of the water basin. At the other end of the unit, the flue gases enter the fire-tubes. As the gases flow through the tubes, additional heat is transferred to the water and produces steam or hot water. The gases are then exhausted through the stack.

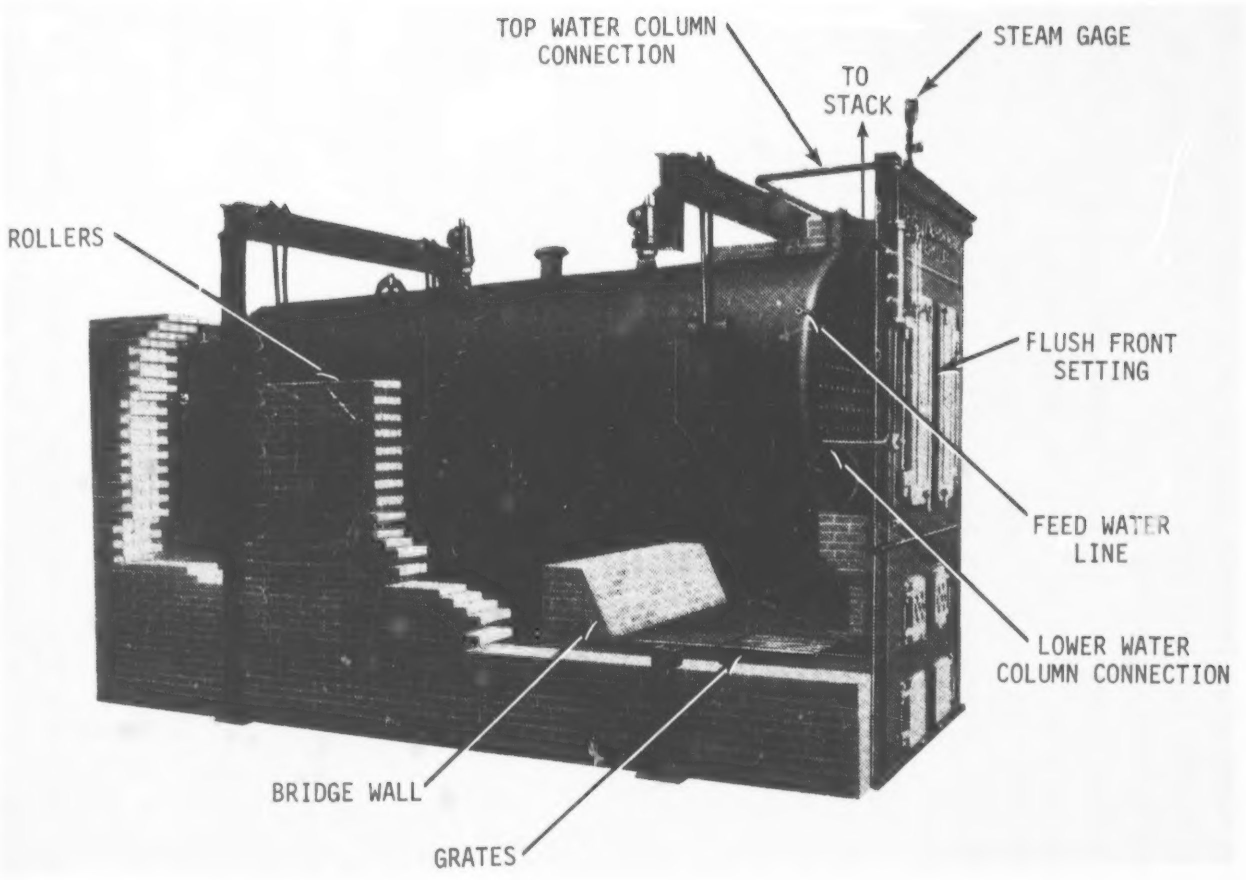

TOP WATER COLUMN CONNECTION
STEAM GAGE
TO STACK
ROLLERS
FLUSH FRONT SETTING
FEED WATER LINE
LOWER WATER COLUMN CONNECTION
BRIDGE WALL
GRATES

Figure 10. Horizontal return-tubular boiler.

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In a four-pass boiler, the furnace is at the end of the unit, as shown in Figure A-11. The first pass goes through the furnace tube, which is an extension of the combustion chamber. The flue gases then pass beneath the furnace tube and then make two passes above the furnace tube. A forced-draft fan must be used to operate a four-pass HRT boiler.

The HRT boiler comes in various sizes ranging from 0.15 to 5.9 MW thermal (0.5 to 20 x 10^6 Btu/h) heat input, with pressures at 100 to 1,700 kPa (15 to 250 psi). The smaller sizes are two-pass units and the larger sizes are four-pass units. Although HRT boilers can fire all fuels, firing of coal can cause scaling and slagging. HRT boilers offer longer boiler life, lower maintenance requirements, and higher firing rates than most fire-tube boilers. Water circulation through these units is poor, however, and thus the heating efficiency is only 70 percent (Thompson et al., 1972).

Scotch Marine

A Scotch marine (Scotch) boiler comes in two-, three-, or four-pass units, consisting of a water-cooled furnace and well-cooled fire-tubes. A two-pass Scotch marine boiler is shown in Figure A-12. The boiler and the furnace are contained in the same shell. The fuels are burned in the lower half of the unit. The products of combustion (flue gases) first flow through the furnace tube, heating the bottom of the water basin, then pass through the fire-tubes, heating the water in the basin.

The capacity of Scotch boilers ranges up to 3.4 MW thermal (12 x 10^6 Btu/h) heat input with pressures up to 1400 kPa (200 psi). Heating efficiency is approximately 80 percent (Thompson et al., 1972). The units range from 0.9 to 2.4 m (3 to 8 ft) in diameter and 1.2 to 5.5 m (4 to 18 ft) long.

Scotch boilers are self-contained, portable, package units. They are compact, require little space, and need no mountings. The internal firing mechanisms can fire all types of fuel. Again, however, firing of coal causes slagging and scaling.

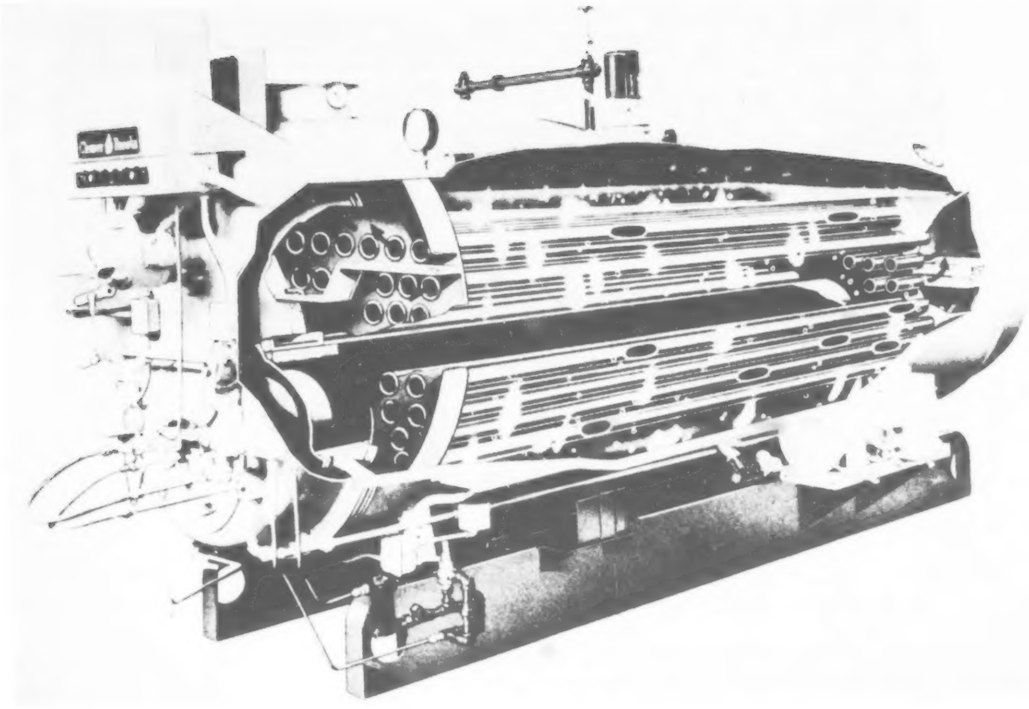

Figure A-11. Horizontal four-pass forced-draft boiler.

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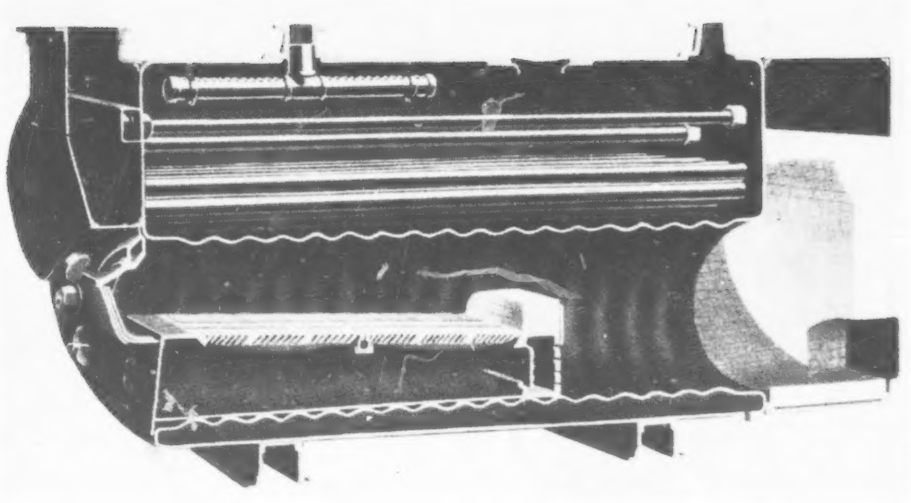

Figure A-12. Scotch marine boiler.

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Vertical

A vertical boiler is a single-pass unit in which the fire-tubes come straight up from the water-cooled furnace. These self-contained, portable units are small and require little space; the initial cost is low. Vertical boilers are classified as exposed-tube or submerged-tube boilers, depending on the length of the fire-tube in relation to the water level.

An exposed-tube boiler is shown in Figure A-13. The fire-tubes extend from the top of the furnace into the steam space. This causes the steam to be superheated and reduces carryover of moisture; however, the fire-tubes have a tendency to crack at the point where they expand into the tube sheet.

A submerged-tube boiler is shown in Figure A-14. The firetubes extend from the top of the furnace to the tube sheet, which is below the water level. This design prevents the ends of the tubes from overheating. A conical flue gas connector is attached above the tube sheet and directs the flue gases into the stack. Use of the vertical, submerged-tube boiler has essentially been abandoned because the connector is difficult to build and has a tendency to leak.

Capacities of vertical boilers range from 0.06 to 0.73 MW thermal (0.2 to 2.5 x 10^6 Btu/h) at pressures of 700 kPa (100 psi). The size range is from 0.91 to 1.5 m (3 to 5 ft) in diameter and 1.5 to 3.0 m (5 to 10 ft) in height. The fire-tubes are 5 to 8 cm (2 to 3 in.) in diameter. These boilers can fire all types of fuels at a heating efficiency of approximately 70 percent (Thompson et al., 1972). The furnace volume can be expanded from its standard size to provide a higher heating efficiency. The volume must be increased if coal is fired. This is accomplished by elevating the boiler and setting it on a refractory base.

Locomotive, Short Firebox, and Compact Boilers

A locomotive boiler is a single-pass horizontal fire-tube unit. It is a portable power boiler with an internal water-jacketed furnace. These units require long fire-tubes to prevent

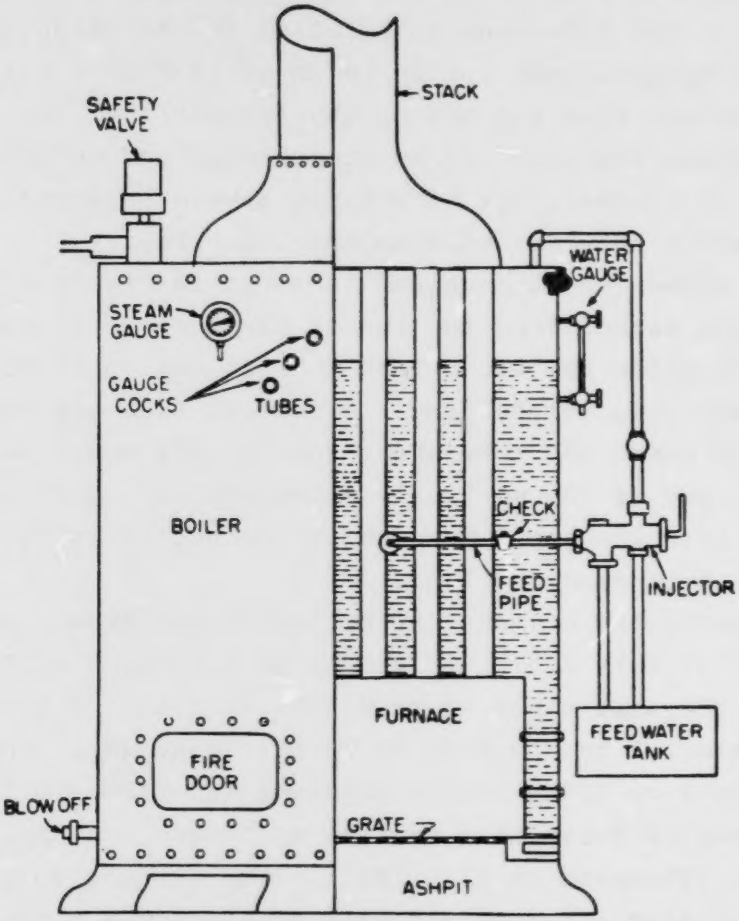
SAFETY VALVE
STACK
WATER GAUGE
STEAM GAUGE
GAUGE COCKS
TUBES
BOILER
CHECK
FEED PIPE
INJECTOR
FURNACE
FEED WATER TANK
FIRE DOOR
BLOWOFF
GRATE
ASHPIT

Figure A-13. Exposed-tube vertical boiler.

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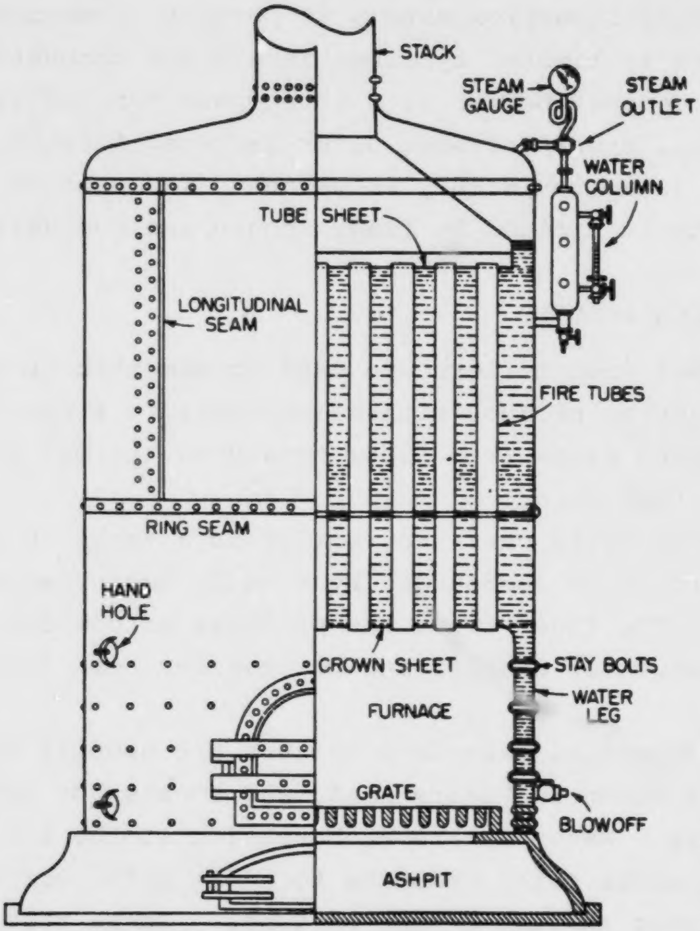
STACK
STEAM GAUGE
STEAM OUTLET
WATER COLUMN
TUBE SHEET
LONGITUDINAL SEAM
FIRE TUBES
RING SEAM
HAND HOLE
CROWN SHEET
STAY BOLTS
FURNACE
WATER LEG
GRATE
BLOWOFF
ASHPIT

Figure A-14. Submerged-tube vertical boiler.

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excessive heat loss. Even so, the heating efficiency is only about 70 percent (Thompson et al., 1972).

A short firebox boiler is a two-pass horizontal firetube unit, which can be used for space heating or process steam generation. This unit requires little floor space, and heating efficiency is approximately 80 percent (Thompson et al., 1972). The unit is limited by flame length and combustion volume.

A compact boiler is a three-pass horizontal boiler with an internal, steel-encased, water-jacketed firebox. Heating efficiency is approximately 80 percent (Thompson et al., 1972). The capacity is limited by flame length and combustion volume.

CAST IRON BOILERS

Cast iron boilers are used in domestic or small commercial operation to produce either low-pressure steam or hot water. Capacities range from 0.001 to 4.0 MW thermal (0.003 to 14 x 10^6 Btu/h) heat input.

A domestic cast iron boiler is a small, round unit in which the furnace is surrounded by a water basin, which is lanced with flues. The flues allow the products of combustion to escape from the combustion chamber and to transfer heat from the gases to the water.

Commercial cast iron boilers are usually square or rectangular, as shown in Figure A-15, and consist of several vertical sections. Water enters each section at the bottom and the steam or hot water exits from the top. In each section the combustion gases pass through a maze of tubes. These tubes transfer heat from the gas to the water. The capacity of the commercial cast iron boiler is determined by the number of sections.

Cast iron boilers are reliable, with an average boiler life of about 50 years (Thompson et al., 1972). They require little maintenance and can handle overloading or demand surges. The major problem associated with cast iron boilers is that the sections tend to deform, which may cause flue gases to leak from the joints.

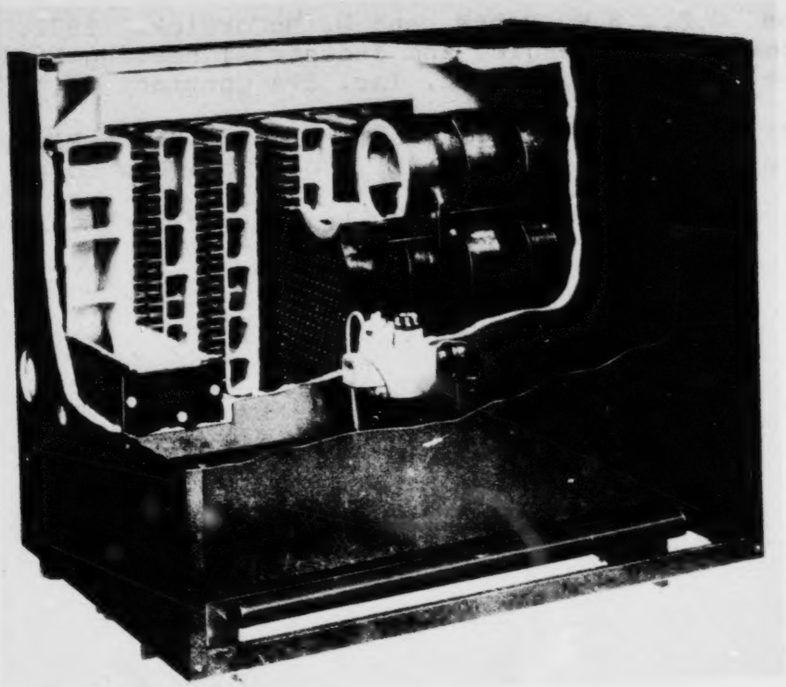

Figure A-15. Cast iron boiler.
(Courtesy of Weil-McLain Company)

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Thompson, O.F., H.R. Mehts, and W. McCormick. 1972. Survey of Domestic, Commercial and Industrial Heating Equipment and Fuel Usage. Catalytic, Inc. EPA Contract No. 68-02-0241.

Woodruff, E.B., and H.B. Lammers. 1977. Steam-Plant Operation. Fourth edition, McGraw-Hill Book Co., New York.

APPENDIX B

DERIVATION OF BOILER CAPACITY DATA

This Appendix provides a detailed description of the data sources and procedures used to develop estimates of boiler capacity. The International System of Units (SI) is not used here, because the original sources were not in SI units. To make it easier to process the data, they were not converted to SI units until final figures were obtained.

Data from three prior studies were updated and expanded to obtain information about the present boiler population. From these studies and the new material available, basic data sheets were compiled for boiler families having the parameters described in Section 2.1. The three studies are:

Battelle Columbus Laboratories. Evaluation of National Boiler Inventory. EPA-650/2-74-032, October 1975. (Referred to here as the Battelle boiler inventory.)

Battelle Columbus Laboratories. Design Trends and Operating Problems in Combustion Modification of Industrial Boilers. EPA-600/2-75-067, March 1974. (Referred to here as the Battelle design study.)

Walden Corp. Systematic Study of Air Pollution from Intermediate Size Fossil Fuel Combustion Equipment. EPA Contract CPA 22-69-85, July 1971. (Referred to here as the Walden boiler study.)

Major Fuel Burning Installation Data File Department of Energy - 1975 Washington, D.C. (Referred to here as MFBI.)

The materials used for the updating and expansion are:

American Boiler Manufacturers Association (ABMA) sales information for fire-tube and water-tube boilers for the years 1966 to 1975.

Shipment data for cast iron boilers for the years 1965 to 1975, supplied by the Hydronics Institute.

Data from the Major Fuel Burning Installation (MFBI) Survey conducted by the Department of Energy in 1975.

The mechanics of developing the basic data are discussed in this Appendix.

In the first step, the data from the Battelle boiler inventory were rearranged into the size categories to be used in this study. The corresponding sizes or capacities are shown below.

Battelle boiler inventory

Size	Capacity, Btu/h
0	5 to 10 x 10^5
1	1 to 2 x 10^6
2	2 to 5 x 10^6
3	5 to 10 x 10^6
4	1 to 2 x 10^7
5	2 to 5 x 10^7
6	5 to 10 x 10^7
7	1 to 2 x 10^8
8	2 to 5 x 10^8
9	5 to 10 x 10^8
10	1 to 2 x 10^9
11	2 to 5 x 10^9
12	5 to 10 x 10^9
13	1 to 2 x 10^{10}
14	>2 x 10^{10}

Present study

Size	Capacity, 10^6 Btu/h	(Corresponding category)
a)	<10.4	(no corresponding category)
b)	0.4 to 1.5	(size 0, and 1/2 the population in size 1)
c)	1.5 to 10	(1/2 the population in size 1, all of size 2 and 3)
d)	10 to 25	(size 4, and 1/6 the population in size 5)
e)	25 to 50	(5/6 the population in in size 5)
f)	50 to 100	(size 6)
g)	100 to 250	(size 7, and 1/6 the population in size 8)
h)	250 to 500	(5/6 the population in size 8)
i)	500 to 1500	(size 9, and 1/2 the population in size 10)
j)	>1500	(1/2 the population in size 10, and sizes 11, 12, and 13)

Note: Size 14 was excluded from this study because no boilers exist in this category.

The distribution shown above assumes that the number of boilers is evenly distributed in a category.

The capacity data were distributed on the assumption that for each fraction of a category, the average size was equal to the value of the midpoint of the range. For example, to calculate values for sizes b) and c), the population of size 1 (1 to 2 x 10^6 Btu) was distributed with half going into each group: 50 percent of the 1 to 1.5 x 10^6 Btu/h group into size b); and 50 percent of the 1.5 to 2.0 x 10^6 Btu/h group going into size c). The average boiler sizes of the two new groups were assumed to be 1.25 x 10^6 Btu/h and 1.75 x 10^6 Btu/h. The percentage of total capacity contained in each of the two groups was calculated as:

$$\frac{1.25}{3.00}(100) = 42 \text{ percent} \qquad \frac{1.75}{3.00} = 58 \text{ percent}$$

Equivalences between the capacity data from the two studies were:

Size a) None

Size b) All of size 0 and 42 percent of size 1

Size c) 58 percent of size 1 and all of sizes 2 and 3

Size d) All of size 4 and 10 percent of size 5

Size e) 90 percent of size 5

Size f) All of size 6

Size g) All of size 7 and 10 percent of size 8

Size h) 90 percent of size 8

Size i) All of size 9 and 42 percent of size 10

Size j) 58 percent of size 10, all of sizes 11, 12, and 13.

For convenience, the Battelle inventory data for commercial and industrial boilers were combined. The basic Battelle population data are shown in Table B-1.

In the second step, the basic data were divided into three categories representing water-tube, fire-tube, and cast iron boilers. Data from the Battelle design study were used for this step. The size categories in the Battelle report and those chosen for the present report were not exactly comparable. The Battelle data show the percent distribution of the three basic boiler types for various boiler sizes. For this study, the size categories shown below were assumed to have the same distribution of basic boiler types.

Battelle design study	Present study
10 to 50 boiler horsepower (0.335 to 1.68 x 10^6 Btu/h)	0.4 to 1.5 x 10^6 Btu/h
51 to 100 boiler horsepower (1.68 to 3.35 x 10^6 Btu/h)	1.5 to 10 x 10^6 Btu/h
101 to 300 boiler horsepower (3.35 to 10.04 x 10^6 Btu/h)	
10 to 16 x 10^6 Btu/h	10 to 25 x 10^6 Btu/h
17 to 100 x 10^6 Btu/h	25 to 50 x 10^6 Btu/h

The applicable percent distribution from Table A-3 in the Battelle design study is shown below.

Size	Water-tube (%)	Fire-tube (%)	Cast iron (%)	Misc. (%)
0.4 - 1.5	6.0	48.0	45.0	1.0
1.5 - 10	5.8	74.1	19.9	0.2
10 - 25	22.0	78.0		
25 - 50	79.0	21.0		
>50	All water-tube			

It was assumed that the distribution between water-tube, fire-tube, and cast iron was applicable to all the fuel categories shown in Table B-1. Tables B-2, B-3, and B-4 were derived by applying the above percentages to the data in Table B-1. When a data base was established for each of the three boiler categories, the data were further refined by boiler type. The water-tube boiler population was derived from Table B-2 (Battelle boiler inventory). The populations of fire-tube and cast iron boilers were developed from the Walden boiler study, since these data appear to be most comprehensive for these boiler types.

TABLE B-1. COMMERCIAL AND INDUSTRIAL BOILER POPULATION (1971) FROM BATTELLE REDISTRIBUTED INTO THE STUDY SIZE CATEGORIES

Size range, 10^6 Btu/h	Fuel										Total	
	Stoker coal		Pulverized coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	9,341	11,161	718	1,018	19,556	23,790	48,802	58,756	40,225	48,880	118,462	143,605
>1.5 to 10.0	19,712	102,338	1,479	6,359	55,182	281,349	50,965	203,024	61,951	286,464	189,289	879,534
>10.0 to 25.0	3,989	66,590	569	9,578	11,239	178,293	2,837	42,920	8,423	134,708	27,057	432,089
>25.0 to 50.0	3,025	114,646	390	15,650	5,818	210,761	1,083	37,459	4,735	173,989	15,031	552,505
>50.0 to 100.0	1,909	140,588	327	27,197	2,406	175,815	324	24,871	2,382	173,885	7,348	542,356
>100.0 to 250.0	718	102,990	462	69,041	948	137,312	163	23,992	1,078	161,609	3,369	494,944
>250.0 to 500.0	142	44,024	183	59,912	272	89,724	38	13,095	299	99,425	934	306,180
>500.0 to 1500.	17	13,948	56	39,750	54	41,811	6	4,399	98	73,531	231	173,439
>1500	5	11,574	11	26,354	7	13,142	1	2,274	40	172,769	64	226,113
Total	38,858	607,859	4,195	254,859	95,482	1,151,997	104,219	410,790	119,231	1,325,260	361,985	3,750,765

TABLE B-2. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL WATER-TUBE BOILER POPULATION BY FUEL (1971)

Size range, 10^6 Btu/h	Fuel										Total	
	Stoker coal		Pulverized coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity		
>0.4 to 1.5	560	670	43	61	1,173	1,427	2,928	3,525	2,414	2,933	7,118	8,616
>1.5 to 10.0	1,143	5,936	86	369	3,200	16,318	2,956	11,775	3,593	16,615	10,978	51,013
>10.0 to 25.0	878	14,650	125	2,107	2,473	39,224	624	9,442	1,853	29,636	5,953	95,059
>25.0 to 50.0	2,390	90,570	308	12,364	4,596	166,501	856	29,593	3,741	137,451	11,891	436,479
>50.0 to 100.0	1,508	111,065	258	21,486	1,901	138,894	256	19,649	1,882	137,369	5,805	428,463
>100.0 to 250.0	718	102,990	462	69,041	948	137,312	163	23,992	1,078	161,609	3,369	494,944
>250.0 to 500.0	142	44,024	183	59,912	272	89,724	38	13,095	299	99,425	934	306,180
>500.0 to 1500.	17	13,948	56	39,750	54	41,811	6	4,399	98	73,531	231	173,439
>1500	5	11,574	11	26,354	7	13,142	1	2,274	40	172,769	64	226,113
Total	7,361	395,427	1,532	231,444	14,624	644,353	7,828	117,744	14,998	831,338	46,343	2,220,306

TABLE B-3. DISTRIBUTION OF THE INDUSTRIAL/COMMERCIAL FIRE-TUBE BOILER POPULATION BY FUEL (1971)

Size range, 10^6 Btu/h	Fuel											
	Stoker coal		Pulverized coal		Residual oil		Distillate oil		Natural gas		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	4,484	5,357	345	238	9,387	11,419	23,425	28,203	19,308	23,462	56,949	68,679
>1.5 to 10.0	14,607	75,832	1,096	4,712	40,890	208,480	37,765	150,441	45,906	212,270	140,264	651,735
>10.0 to 25.0	3,111	51,940	444	7,471	8,766	139,069	2,213	33,478	6,570	105,072	21,104	337,030
>25.0 to 50.0	635	24,076	82	3,287	1,222	44,260	227	7,866	994	36,538	3,160	116,027
>50.0 to 100.0	401	29,523	69	5,711	505	36,921	68	5,223	500	36,516	1,543	113,894
>100.0 to 250.0												
>250.0 to 500.0												
>500.0 to 1500.												
>1500												
Total	23,238	186,728	2,036	21,419	60,770	440,149	63,698	225,211	73,278	413,858	223,020	1,287,365

TABLE B-4. DISTRIBUTION OF THE INDUSTRIAL/COMMERCIAL CAST IRON BOILER POPULATION BY FUEL (1971)

Size range, 10^6 Btu/h	Fuel										Total	
	Stoker coal		Pulverized coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	4,203	5,022	323	458	8,800	10,706	21,961	26,440	18,101	21,996	53,388	64,622
>1.5 to 10.0	3,923	20,365	294	1,265	10,987	55,988	10,142	40,402	12,328	57,006	37,668	175,026
>10.0 to 25.0												
>25.0 to 50.0												
>50.0 to 100.0												
>100.0 to 250.0												
>250.0 to 500.0												
>500.0 to 1500.												
>1500												
Total	8,126	25,387	617	1,723	19,781	66,694	32,103	66,842	30,429	79,002	91,056	239,648

Following are details of the procedure for deriving the data for water-tube, fire-tube, and cast iron boilers.

WATER-TUBE BOILERS

It was first necessary to determine how many water-tube boilers were erected in the field, and how many were package units (shop-fabricated). The Battelle design study had established that only water-tube boilers were field-erected. The percentages of different types of construction for the size ranges shown in Table B-2 were derived from Battelle design study data. These are shown in Table B-5. These percentages were used to divide the data in Table B-2 into the information presented in Table B-6, which shows data for field-erected units, and Table B-7, which shows data for package units. Pulverized-coal-fired (PC) units having a capacity less than 100 x 10^6 Btu/h were excluded at this point, based on information from ABMA that no PC units of this size were constructed.

Of the water-tube boilers, the stoker-fed coal units were divided into overfeed, underfeed, and spreader stokers. The percentages of the stoker types were taken from the Battelle design study, and are presented for the different size catagories in Table B-8. These are normalized percentages for the three categories of stoker.

The combined percentage of boilers in the 51 to 100 bhp and the 101 to 300 bhp categories was obtained by calculating the population in these two categories from data in Table 7 of the Battelle boiler inventory. The calculations followed the methodology described previously for rearranging the Battelle data into the size categories used in the present study. These population figures and percentages from the Battelle design study were used to derive the combined percentages for the 1.5 to 10 x 10^6 Btu/h category.

TABLE B-5. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL WATER-TUBE BOILER POPULATION BY CONSTRUCTION METHOD

	Percent of total construction method	
	Package	Field-erected
>10.0 to 25.0	70.0	30.0
>25.0 to 50.0	70.0	30.0
>50.0 to 100.0	65.0	35.0
>100.0 to 250.0	25.0	75.0
>250.0 to 500.0	0.5	99.5
>500.0 to 1500.0	0	100
>1500	0	100

TABLE B-6. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL FIELD-ERECTED, WATER-TUBE BOILERS BY FUEL (1971)

Size range, 10^6 Btu/h	Fuel										Total	
	Pulverized coal		Stoker coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5												
>1.5 to 10.0												
>10.0 to 25.0	263	4,395			742	11,767	187	2,833	556	8,891	1,748	27,886
>25.0 to 50.0	717	27,171			1,379	49,950	257	8,878	1,122	41,235	3,475	127,234
>50.0 to 100.0	528	38,872			665	48,613	90	6,877	659	48,079	1,942	142,441
>100.0 to 250.0	538	77,242	346	51,781	711	102,984	122	17,994	808	121,207	2,525	371,208
>250.0 to 500.0	141	43,774	182	59,612	271	89,275	37	12,840	298	98,928	929	304,429
>500.0 to 1500.	17	13,948	56	39,750	54	41,811	6	4,399	98	73,531	231	173,439
>1500	5	11,574	11	26,354	7	13,142	1	2,274	40	172,769	64	226,113
Total	2,209	216,976	595	177,497	3,829	357,542	700	56,095	3,581	564,640	10,914	1,372,750

TABLE B-7. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL WATER-TUBE BOILERS BY FUEL (1971)

Size range, 10⁶ Btu/h	Fuel										Total	
	Pulverized coal		Stoker coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	560	670			1,173	1,427	2,928	3,525	2,414	2,933	7,075	8,555
>1.5 to 10.0	1,143	5,936			3,200	16,318	2,956	11,775	3,593	16,615	10,892	50,644
>10.0 to 25.0	615	10,255			1,731	27,457	437	6,609	1,297	20,745	4,080	65,066
>25.0 to 50.0	1,673	63,399			3,217	116,551	599	20,715	2,619	96,216	8,108	296,881
>50.0 to 100.0	980	72,193			1,236	90,281	166	12,722	1,223	89,290	3,605	264,536
>100.0 to 250.0	180	25,748	116	17,260	237	34,328	41	5,998	270	40,402	844	123,736
>250.0 to 500.0	1	250	1	300	1	449	1	255	1	497	5	1,751
>500.0 to 1500.												
>1500												
Total	5,152	8,451	117	17,560	10,795	86,811	7,128	61,599	11,417	266,698	34,609	811,169

TABLE B-8. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL STOKER-FIRED BOILERS

	Percentage of total		
	Spreader stoker	Underfeed stoker	Overfeed stoker
>0.4 to 1.5		95	5
>1.5 to 10.0	9	81	10
>10.0 to 25.0	16	74	10
>25.0 to 50.0	21	63	16
>50.0 to 100.0	21	63	16
>100.0 to 250.0	63	25	12
>250.0 to 500.0	55	27	18
>500.0 to 1500.0	55	27	18
>1500	55	27	18

Tables B-9 and B-10 show the distribution among types of stokers for field-erected and package boilers. It was assumed that the same distribution patterns applied in both categories.

The ABMA sales data were then used to update the figures. These sales data for all water-tube boilers are shown in Table B-11. Tables B-12 and B-13 show the distribution of field-erected and package boilers; Table B-14 shows the distribution of oil-fired boilers into units using distillate and residual oil. The figures in the sales tables were obtained by taking raw data from ABMA and adjusting it to reflect an ABMA estimate of 27 percent replacement boilers and 73 percent new boilers. The distributions between field-erected and package boilers, and between units firing residual oil and firing distillate oil, were made by using elements from the Battelle design study. Table B-15 shows the combined data from the Battelle boiler study and the ABMA sales figures.

FIRE-TUBE BOILERS

Data from the Walden boiler study were used to develop the data base for fire-tube boiler capacity. Tables 4-1 and 4-2 of the Walden study show the 1967 fire-tube boiler population as:

Number of units	Capacity, 10^6 Btu/h
239,000	813,000

An attempt was made to distribute data from the Walden boiler study by size according to ratios derived from ABMA sales data. (A description of the sales data is presented later in this section.) The results that were obtained were obviously erroneous. When the average size from the Walden data (3.4×10^6 Btu/h) is compared with the average size from the sales data (6.2×10^6 Btu/h), it is clear that a significant shift toward larger sizes has occurred in recent years. Data from the sales records were all within three size categories (0.4 to 1.5, 1.5 to 10, and 10 to 25 x 10^6 Btu/h). Most of the capacity was in the two

TABLE B-9. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL FIELD-ERECTED, STOKER-FIRED, WATER-TUBE BOILERS (1971)

Size range, 10^6 Btu/h	Spreader stoker		Underfeed stoker		Overfeed stoker		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5								
>1.5 to 10.0								
>10.0 to 25.0	42	703	195	3,252	26	440	263	4,395
>25.0 to 50.0	151	5,706	452	17,118	114	4,347	717	27,171
>50.0 to 100.0	111	8,163	333	24,489	84	6,220	528	38,872
>100.0 to 250.0	339	48,662	135	19,311	64	9,269	538	77,242
>250.0 to 500.0	78	23,962	37	11,627	25	7,675	140	43,264
>500.0 to 1500.0	9	7,700	5	3,780	3	2,519	17	13,999
>1500	3	6,300	1	3,111	1	2,074	5	11,485
Total	733	101,196	1,158	82,688	317	32,544	2,208	216,428

TABLE B-10. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL PACKAGE, STOKER, WATER-TUBE BOILERS (1971)

Size range, 10^6 Btu/h	Spreader stoker		Underfeed stoker		Overfeed stoker		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	0	0	532	637	28	33	560	670
>1.5 to 10.0	103	534	1,926	4,808	114	594	1,143	5,936
>10.0 to 25.0	98	1,641	455	7,589	62	1,025	615	10,255
>25.0 to 50.0	351	13,314	1,054	39,941	268	10,144	1,673	63,399
>50.0 to 100.0	206	15,161	617	45,482	157	11,550	980	72,193
>100.0 to 250.0	113	16,222	45	6,437	22	3,089	180	25,748
>250.0 to 500.0	1	251	1	259	1	250	3	760
>500.0 to 1500.0								
>1500								
Total	872	47,123	3,630	105,153	652	26,685	5,154	178,961

TABLE B-11. DISTRIBUTION OF WATER-TUBE BOILER SALES BY FUEL (1969-1975)

Size range, 10^6 Btu/h	Fuel													
	Pulverized coal		Spreader stoker coal		Underfeed stoker coal		Overfeed stoker coal		Residual and distillate oil		Natural gas		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5														
>1.5 to 10.0	0	0	0	0	2	20	0	0	24	240	31	282	57	542
>10.0 to 25.0	0	0	2	50	10	182	1	25	402	8,090	935	18,458	1,350	26,805
>25.0 to 50.0	0	0	26	1,150	5	152	27	989	664	25,313	1,537	58,091	2,259	85,695
>50.0 to 100.0	0	0	35	2,758			11	840	474	36,320	1,251	90,279	1,771	130,197
>100.0 to 250.0	7	1,325	69	12,179			5	750	450	69,518	696	103,836	1,227	187,608
>250.0 to 500.0	11	4,260	5	1,600					43	15,635	53	18,041	112	39,536
>500.0 to 1500.0	11	6,835							9	6,350	7	4,850	27	18,035
>1500									1	6,024	0	0	1	6,024
Total	29	12,420	137	17,737	17	354	44	2,604	2,067	167,490	4,510	293,837	6,804	494,442

TABLE B-12. DISTRIBUTION OF FIELD-ERECTED, WATER-TUBE BOILER SALES BY FUEL (1969-1975)

Size range, 10^6 Btu/h	Pulverized coal		Spreader stoker coal		Underfeed stoker coal		Overfeed stoker coal		Oil		Natural gas		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5														
>1.5 to 10.0														
>10.0 to 25.0			1	15	3	55			121	2,427	280	5,537	405	8,044
>25.0 to 50.0			8	345	2	46	8	277	199	7,594	461	17,437	678	25,699
>50.0 to 100.0			12	965			4	279	166	12,712	438	31,598	620	45,554
>100.0 to 250.0	5	994	52	9,134			4	562	337	52,138	522	7,787	920	140,705
>250.0 to 500.0	11	4,260	5	1,600					43	15,635	44	15,635	103	37,130
>500.0 to 1500.0	11	6,835							9	6,530	7	4,850	27	18,035
>1500									1	6,024			1	6,024
Total	27	12,089	78	12,059	5	101	16	1,118	876	102,880	1,753	152,934	2,755	281,181

TABLE B-13. DISTRIBUTION OF PACKAGE WATER-TUBE BOILER SALES BY FUEL (1969-1975)

Size range, 10^6 Btu/h	Fuel												Total	
	Pulverized coal		Spreader stoker coal		Underfeed stoker coal		Overfeed stoker coal		Residual and distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5														
>1.5 to 10.0	0	0	0	0	2	20	0	0	24	240	31	282	57	542
>10.0 to 25.0	0	0	1	35	7	127	1	25	281	5,663	655	12,921	945	18,771
>25.0 to 50.0	0	0	18	805	3	106	19	712	465	17,719	1,076	40,664	1,581	60,006
>50.0 to 100.0	0	0	23	1,793			7	561	308	23,608	813	58,681	1,151	84,643
>100.0 to 250.0	2	331	17	3,045			1	188	113	17,380	174	25,959	307	46,903
>250.0 to 500.0	0	0	0	0					0	0	9	2,406	9	2,406
>500.0 to 1500.0														
>1500														
Total	2	331	59	5,678	12	253	28	1,485	1,191	65,610	2,758	140,913	4,050	213,271

TABLE B-14. DISTRIBUTION OF OIL-FIRED, WATER-TUBE BOILER SALES (1969-1975)

	Residual oil		Distillate oil		Total	
	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5						
>1.5 to 10.0	21	211	3	29	24	240
>10.0 to 25.0	354	7,119	48	971	402	8,090
>25.0 to 50.0	584	22,275	80	3,038	664	25,313
>50.0 to 100.0	417	31,962	57	4,358	474	36,320
>100.0 to 250.0	396	61,176	54	8,342	450	69,518
>250.0 to 500.0	38	13,759	5	1,876	43	15,635
>500.0 to 1500.0	8	5,588	1	762	9	6,350
>1500	1	6,024			1	6,024
Total	1,819	148,114	248	19,376	2,067	167,490

TABLE B-15. DISTRIBUTION OF WATER-TUBE BOILER POPULATION (1977) BY FUEL

Size range, 10^6 Btu/h	Fuel														Total	
	Pulverized coal		Spreader stoker coal		Underfeed stoker coal		Overfeed stoker coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	0	0	0	0	512	500	28	30	1,173	1,400	2,928	3,500	2,414	2,900	7,075	8,330
>1.5 to 10.0	0	0	103	500	928	4,800	114	600	3,215	16,500	2,958	11,800	3,616	16,800	10,934	51,000
>10.0 to 25.0	0	0	142	2,400	657	11,000	89	1,500	2,731	44,400	659	10,100	2,535	43,100	6,813	112,500
>25.0 to 50.0	0	0	521	19,900	1,509	57,200	402	15,100	5,022	182,800	914	31,800	4,863	179,900	13,231	486,700
>50.0 to 100.0	0	0	343	25,400	950	71,000	249	18,300	2,205	162,200	298	22,900	2,795	203,200	6,840	503,000
>100.0 to 250.0	467	70,000	504	73,700	180	25,700	90	12,900	1,237	182,000	202	30,200	1,586	237,500	4,266	632,000
>250.0 to 500.0	191	63,000	83	25,600	38	11,900	26	8,000	300	99,800	41	14,500	339	112,600	1,018	335,400
>500.0 to 1500.0	64	44,700	9	7,700	5	3,800	3	2,500	62	47,400	7	5,200	103	77,100	253	188,400
>1500	11	26,400	3	6,100	1	3,100	1	2,100	8	19,200	1	2,300	40	172,800	65	232,200
Totals	733	204,100	1,708	151,500	4,800	189,000	1,002	61,030	15,953	755,700	8,000	132,300	18,291	1,045,900	50,495	2,549,530

larger sizes. It was therefore assumed that the data from the Walden boiler study would follow the same general pattern, with the number of boilers in smaller sizes being somewhat higher because of the smaller average capacity per unit reflected in these data. By trial and error, it was determined that the following percent distribution was consistent with the Walden data on population and capacity, and also consistent with the general pattern of the sales data:

	Capacity by size categories, 10^6 Btu/h				
	0.4 to 1.5	1.5 to 10	10 to 25	25 to 50	Total
Percentage of capacity	21.5	33.5	30	15	100
No. of boilers	174,795	272,355	243,900	121,950	813,000
Capacity, 10^6 Btu/h	174,795	47,366	13,937	3,252	239,350

The capacity for each size category was determined by applying the assumed percent distribution to the data from the Walden boiler study. The population figures were derived by assuming the average boiler size in each category to be the midpoint of the capacity range. The figures derived from the assumed distribution totaled close to those given in the Walden study; hence, the derived data were considered sufficiently accurate for the purposes of this study.

The fuel consumption data shown in the Walden boiler study (Table 3-2, p. 56) were converted to Btu's as follows:

Coal: $(11 \times 10^6$ tons$) \times (24 \times 10^6$ Btu/ton$) = 264 \times 10^{12}$ Btu

Residual oil: $(98 \times 10^6$ bbl$) \times (42$ gal/bbl$) \times (149{,}000$ Btu/gal$)$
$= 613 \times 10^{12}$ Btu

Distillate oil: $(69 \times 10^6$ bbl$) \times (42$ gal/bbl$) \times (139{,}000$ Btu/ga
$= 403 \times 10^{12}$ Btu

Gas: $(1.12 \times 10^{12}$ ft$^3) \times (1000$ Btu/ft$^3) = 1120 \times 10^{12}$ Btu

Total $= 2400 \times 10^{12}$ Btu/yr

The percentage contributed by each fuel to the total consumption was then calculated:

Distribution by fuel, percent	
Coal	11.0
Residual oil	25.6
Distillate oil	16.7
Gas	46.7
	100.0

Capacity was assumed to be distributed proportional to fuel consumption, and was calculated on the basis of these percentages:

Fuel		Capacity, 10^6 Btu/h
Coal	(11%)	89,430
Residual oil	(25.6%)	208,128
Distillate oil	(16.7%)	135,771
Gas	(46.7%)	379,671
Total		813,000

The distribution of total capacity among the various types of fire-tube boilers (Scotch, firebox, HRT, and others) was derived from data in the Battelle design study (Table A-3):

1) Data in the 10 to 50 boiler hp (0.335 to 1.67 x 10^6 Btu/h) category were assumed to be applicable to the 0.4 to 1.5 x 10^6 Btu/h category of the present study. The normalized percentages for this category are shown below.

	Battelle percentages	Normalized percentages
Scotch	15	31
Firebox	25	52
HRT	5	10
Other	3	7

2) Data from the 51 to 100 boiler hp (1.67 to 3.35 x 10^6 Btu/h) and the 101 to 300 boiler hp (1.67 to 10.0 x 10^6 Btu/h) were taken to represent the 1.5 to 10 x 10^6 Btu/h category.

	Battelle percentages		Normalized percentage		Percentage used
	51 to 100	101 to 300	51 to 100	101 to 300	1.5 to 10 x 10^6
Scotch	20	30	34	37	36
Firebox	25	30	43	38	40
HRT	10	15	17	19	18
Other	3.5	5	6	6	6

For sizes 10 to 25 x 10^6 Btu/h and 25 to 50 x 10^6 Btu/h in the present study, the distributions in Battelle for 10 to 16 x 10^6 Btu/h and 25 to 50 x 10^6 Btu/h were considered applicable. The normalized percentages are:

	Battelle percentage 10 to 16 x 10^6 Btu/h	Normalized percentage 10 to 25 x 10^6 Btu/h	Battelle percentage 25 to 50 x 10^6 Btu/h	Normalized percentage 25 to 50 x 10^6 Btu/h
Scotch	30	38	10	48
Firebox	25	32	10	48
HRT	20	26	1	4
Other	3	4	0	0

Table B-16 shows data from the Walden boiler study distributed by boiler size and fuel type. Tables B-17, B-18, B-19, and B-20 show the data obtained by using the distribution by boiler type (given above) for each type of fuel. The distribution factors were assumed to be independent of type of fuel.

Next, the ABMA sales data were tabulated. The size categories used by ABMA were matched with those for the present study:

ABMA size range		Present study size range
Boiler hp	10^6 Btu/h	10^6 Btu/h
15 to 50	0.502 to 1.67	0.5 to 1.5
50 to 300	1.670 to 10.0	1.5 to 10.0
300 to 700	10.0 to 23.4	10.0 to 25.0

ABMA data gave the size of the boiler and the number of units sold. Capacity was calculated for each category, after excluding the 27 percent that was assumed to represent replacement boilers.

TABLE B-16. COMMERCIAL AND INDUSTRIAL FIRE-TUBE BOILER POPULATION (1967) REDISTRIBUTED INTO THE STUDY-SIZE CATEGORIES[a]

Size range, 10^6 Btu/h	Coal		Residual oil		Distillate oil		Natural gas		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	19,227	19,227	44,748	44,748	29,191	29,191	81,629	81,629	174,795	174,795
>1.5 to 10	5,210	29,959	12,126	69,723	7,910	45,483	22,120	127,190	47,366	272,355
>10 to 25	1,533	26,829	3,568	62,438	2,327	40,731	6,509	113,902	13,937	243,900
>25 to 50	358	13,415	833	31,219	543	20,366	1,518	56,950	3,252	121,950
Total	26,328	89,430	61,275	208,128	39,971	135,771	111,776	379,671	239,350	813,000

[a] Ehrenfeld et al., 1971.

TABLE B-17. DISTRIBUTION OF COMMERCIAL/INDUSTRIAL COAL-FIRED FIRE-TUBE BOILER POPULATION BY TYPE (1967)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	5,960	5,960	9,998	9,998	1,923	1,923	1,346	1,346	19,227	19,227
>1.5 to 10.0	1,876	10,785	2,084	11,984	938	5,393	312	1,797	5,210	29,959
>10.0 to 25.0	583	10,195	491	8,585	399	6,976	60	1,073	1,533	26,829
>25.0 to 50.0	172	6,439	172	6,439	14	537	0	0	358	13,415
Total	8,591	33,379	12,745	37,006	3,274	14,829	1,718	4,216	26,328	89,430

TABLE B-18. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL RESIDUAL-OIL-FIRED FIRE-TUBE BOILER POPULATION BY TYPE (1967)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	13,872	13,872	23,269	23,269	4,475	4,475	3,132	3,132	44,748	44,748
>1.5 to 10.0	4,365	25,100	4,850	27,889	2,183	12,550	728	4,184	12,126	69,723
>10.0 to 25.0	1,356	23,726	1,142	19,980	928	16,234	142	2,498	3,568	62,438
>25.0 to 50.0	400	14,985	400	14,985	0	0	33	1,249	833	31,219
Total	19,993	77,683	29,661	86,123	7,586	33,259	4,035	11,063	61,275	208,128

TABLE B-19. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL DISTILLATE-OIL-FIRED FIRE-TUBE BOILER POPULATION BY TYPE (1967)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	9,049	9,049	15,179	15,179	2,919	2,919	2,044	2,044	29,191	29,191
>1.5 to 10.0	2,848	16,374	3,164	18,193	1,424	8,187	474	2,729	7,910	45,483
>10.0 to 25.0	884	15,478	745	13,034	605	10,590	93	1,629	2,327	40,731
>25.0 to 50.0	261	9,776	261	9,776	21	814	0	0	543	20,366
Total	13,042	50,677	19,349	56,182	4,969	22,510	2,611	6,402	39,971	135,771

TABLE B-20. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL NATURAL-GAS-FIRED FIRE-TUBE BOILER POPULATION BY TYPE (1967)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	25,305	25,305	42,447	42,447	8,163	8,163	5,714	5,714	81,629	81,629
>1.5 to 10.0	7,963	45,788	8,848	50,876	3,982	22,894	1,327	7,632	22,120	127,190
>10.0 to 25.0	2,473	43,283	2,083	36,449	1,692	29,615	261	4,555	6,509	113,902
>25.0 to 50.0	729	27,336	729	27,336	60	2,278	0	0	1,518	56,950
Total	36,470	141,712	54,107	157,108	13,897	62,950	7,302	17,901	111,776	379,671

Size	Btu/boiler hp	No. of boilers	No. of boilers (adjusted)	Capacity, 10^6 Btu/h
15 boiler hp	33,480	712	519.8	261.0

The basic data aggregated from the sales records are shown below:

	Capacity range, 10^6 Btu/h		
	0.5 to 1.5	15 to 10	10 to 25
No. of boilers	4,373	27,021	4,331
Capacity	4,362	139,584	76,215

To distribute these data by fuel type, the records on oil, gas, and combination firing were examined. These are shown below:

Number of boilers

Year	Oil-fired	Gas-fired	Combination-fired	Total
1966	2,827	2,177	1,598	6,602
1967	2,131	1,819	1,564	5,514
1968	1,900	1,868	1,524	5,292
1969	2,319	2,427	1,838	6,584
1970	1,545	1,587	1,600	4,732
1971	1,538	1,166	1,718	4,422
1972	1,741	897	1,577	4,215
1973	2,088	808	1,922	4,818
1974	1,536	726	1,476	3,738
1975	1,294	439	1,233	2,966
	18,919	13,914	16,050	48,883

Total number of oil- and gas-fired units (from sales data) = 32,833

The boiler population after adjustments for replacement boilers had a combined capacity of 220,200 x 10^6 Btu/h as compared with a population shown by the Walden boiler study of 813,000 x 10^6 Btu/h. The general trend toward increased use of oil (instead of gas) that started in 1971 was not specifically considered in figuring the distribution of the population by fuel type. The fractions were derived as averages over the last 10 years of sales:

$$\text{Fraction for oil} = \frac{18{,}919}{32{,}833} = 0.576$$

$$\text{Fraction for gas} = \frac{13{,}914}{32{,}833} = 0.424$$

For this derivation, it was assumed that the combined firing of gas and oil in boilers would have the same relative fuel distribution as is found in single fuel boilers.

The distribution between residual oil and distillate oil was based on percentages derived from the Walden boiler study and presented earlier. The distribution is as follows:

Residual oil = 613 x 10^{12} Btu/yr
Distillate oil = 403 x 10^{12} Btu/yr
Total oil = 1016 x 10^{12} Btu/yr

$$\text{Fraction residual} = \frac{613}{1016} = 0.603$$

$$\text{Fraction distillate} = \frac{403}{1016} = 0.397$$

Using these factors and the boiler population data given above, Table B-21 was developed, to show the population and capacity of boilers sold between 1966 and 1975 on the basis of size and fuel type.

Sales records also showed that no coal-fired fire-tube boilers were sold in that period.

To distribute the sales of fire-tube boilers by type of fire-tube (i.e., Scotch, Firebox, HRT, other), data on the units installed in 1970 were taken from the design study (p. A-22). These values were normalized to obtain the distribution by type. The percentages are given in terms of the Battelle size range, which corresponds to the range for this study as follows:

10 to 50 = 0.4 to 1.5 x 10^6 Btu/h

50 to 100 and
101 to 300 boiler hp = 1.5 to 10 x 10^6 Btu/h

10 to 16 x 10^6 Btu/h = 10 to 25 x 10^6 Btu/h

17 to 100 x 10^6 Btu/h = 25 to 100 x 10^6 Btu/h

TABLE B-21. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL FIRE-TUBE BOILER SALES BY FUEL (1966-1975)

Size range, 10^6 Btu/h	Residual oil		Distillate oil		Natural gas		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	1,519	1,515	1,000	998	1,854	1,849	4,373	4,362
>1.5 to 10	9,385	48,481	6,179	31,919	11,457	59,184	27,021	139,584
>10 to 25	1,504	26,472	991	17,428	1,836	32,315	4,331	76,215
Total	12,408	76,468	8,170	50,345	15,147	93,348	35,725	220,161

Type of Fire-tube Boilers, by percentage

	10 to 50 boiler hp		50 to 100 boiler hp		101 to 300 boiler hp		
	Battelle	Normalized	Battelle	Normalized	Battelle	Normalized	Used
Scotch	11	28.9	22	51.2	41	51.9	51
Firebox	18	47.4	17	39.5	35	44.3	42
HRT	nil	nil	nil	nil	1	1.3	1
Other	9	23.7	4	9.3	2	2.5	6
		100.0		100.0		100.0	100

	10 to 16 x 10^6 Btu/h		17 to 100 x 10^6 Btu/h	
	Battelle	Normalized	Battelle	Normalized
Scotch	44	51.8	5	83.3
Firebox	40	47.0	1	16.7
HRT	nil	nil	nil	nil
Other	1	1.2		nil
		100.0		100.0

An approximate percentage was used for the combined factor for the 1.5 to 10 x 10^6 Btu/h category, because earlier calculations showed that a more precise treatment produced no significant change in the approximate values. The above factors were applied to the sales data to develop Tables B-22, B-23, and B-24, which show the distribution of fire-tube boiler sales by size, by fuel, and by type.

The total fire-tube boiler population, distributed by size and then by fuel, was developed by combining the data from the Walden boiler study with the ABMA sales data to obtain Table B-25. The total fire-tube boiler population by fuel, distributed by size and by type, was developed by combining the appropriate data from Walden with ABMA sales data to obtain Tables B-26, B-27, B-28, and B-29.

CAST IRON BOILERS

Capacity estimates for cast iron boilers were based on information from the Walden boiler study (Tables 4-1 and 4-2), which shows:

TABLE B-22. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL RESIDUAL-OIL-FIRED FIRE-TUBE BOILER SALES BY TYPE (1966-1975)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	439	438	720	718	0		360	359	1,159	1,515
>1.5 to 10.0	4,786	24,725	3,942	20,362	94	485	563	2,909	9,385	48,481
>10.0 to 25.0	779	13,712	707	12,442	0		18	318	1,504	26,472
Total	6,004	38,875	5,369	33,522	94	485	941	3,586	12,408	76,468

TABLE B-23. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL DISTILLATE-OIL-FIRED FIRE-TUBE BOILER SALES BY TYPE (1966-1975)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	289	288	474	473	0		237	237	1,000	998
>1.5 to 10.0	3,151	16,279	2,595	13,406	62	319	371	1,915	6,179	31,919
>10.0 to 25.0	513	9,028	466	8,191	0		12	209	991	17,428
Total	3,953	25,595	3,535	22,070	62	319	620	2,361	8,170	50,345

TABLE B-24. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL NATURAL-GAS-FIRED FIRE-TUBE BOILER SALES BY TYPE (1966-1975)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	536	534	879	876	0		439	439	1,854	1,849
>1.5 to 10.0	5,843	30,184	4,812	24,857	115	592	687	3,551	11,457	59,184
>10.0 to 25.0	951	16,739	863	15,188	0		22	388	1,836	32,315
Total	7,330	47,457	6,554	40,921	115	592	1,148	4,378	15,147	93,348

TABLE B-25. DISTRIBUTION OF TOTAL FIRE-TUBE BOILER POPULATION BY FUEL (1977)

Size range, 10^6 Btu/h	Coal		Residual oil		Distillate oil		Natural gas		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	19,227	19,227	46,267	46,263	30,191	30,189	83,483	83,478	179,168	179,157
>1.5 to 10.0	5,210	29,959	21,511	118,204	14,089	77,402	33,577	186,374	74,387	411,939
>10.0 to 25.0	1,533	26,829	5,072	88,910	3,318	58,159	8,345	146,217	18,268	320,115
>25.0 to 50.0	358	13,415	833	31,219	543	20,366	1,518	56,950	3,252	121,950
Total	26,238	89,430	73,683	284,596	48,141	186,116	126,923	473,019	275,075	1,033,161

TABLE B-26. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL COAL-FIRED FIRE-TUBE BOILER POPULATION BY TYPE (1977)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Totals	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	5,960	5,960	9,998	9,998	1,923	1,923	1,346	1,346	19,227	19,227
>1.5 to 10.0	1,876	10,785	2,084	11,984	938	5,393	312	1,797	5,210	29,959
>10.0 to 25.0	583	10,195	491	8,585	399	6,976	60	1,073	1,533	26,829
>25.0 to 50.0	172	6,439	172	6,439	14	537	0		358	13,415
Total	8,591	33,379	12,745	37,006	3,274	14,829	1,718	4,216	26,328	89,430

TABLE B-27. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL RESIDUAL-OIL-FIRED FIRE-TUBE BOILER POPULATION BY TYPE (1977)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	14,311	14,310	23,989	23,987	4,475	4,475	3,492	3,491	46,267	46,263
>1.5 to 10.0	9,151	49,825	8,792	48,251	2,277	13,035	1,291	7,093	21,511	118,204
>10.0 to 25.0	2,135	37,438	1,849	32,422	928	16,234	160	2,816	5,072	88,910
>25.0 to 50.0	400	14,985	400	14,985	0	0	33	1,249	833	31,219
Total	25,997	116,558	35,030	119,645	7,680	33,744	4,976	14,649	73,683	284,596

TABLE B-28. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL DISTILLATE-OIL-FIRED FIRE-TUBE BOILER POPULATION BY TYPE (1977)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	9,338	9,337	15,653	15,652	2,919	2,919	2,281	2,281	30,191	30,189
>1.5 to 10.0	5,999	32,653	5,759	31,599	1,486	8,506	845	4,644	14,089	77,402
>10.0 to 25.0	1,397	24,506	1,211	21,225	605	10,590	105	1,838	3,318	58,159
>25.0 to 50.0	261	9,776	261	9,776	21	814	0	0	543	20,366
Total	16,995	76,272	22,884	78,252	5,031	22,829	3,231	8,763	48,141	186,116

TABLE B-29. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL NATURAL-GAS-FIRED FIRE-TUBE BOILER POPULATION BY TYPE (1977)

Size range, 10^6 Btu/h	Scotch		Firebox		HRT		Others		Total	
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
>0.4 to 1.5	25,851	25,839	43,326	43,323	8,163	8,163	6,153	6,153	83,483	83,478
>1.5 to 10.0	13,806	75,972	13,660	75,733	4,097	23,486	2,014	11,183	33,577	186,374
>10.0 to 25.0	3,424	60,022	2,946	51,637	1,692	29,615	283	4,943	8,345	146,217
>25.0 to 50.0	729	27,336	729	27,336	60	2,278	0	0	1,518	56,950
Total	43,800	189,169	60,661	198,029	14,012	63,542	8,450	22,279	126,923	473,019

No. of units	Capacity
1270×10^3	757×10^6 pounds steam/h (assumes 1000 Btu/lb of steam)

Annual fuel consumption data from the same source (Table 3-2) were used to derive the distribution of boilers by fuel type.

Coal = $(11 \times 10^6$ tons/yr$) \times (24 \times 10^6$ Btu/ton$) = 264 \times 10^{12}$ Btu/yr

Residual oil = $(56 \times 10^6$ bbl/yr$) \times (42$ gal/bbl$) \times (149 \times 10^3$ Btu/gal) $= 350 \times 10^{12}$ Btu/yr

Distillate oil = $(37 \times 10^6$ bbl/yr$) \times (42$ gal/bbl$) \times (139 \times 10^3$ Btu/gal$) = 216 \times 10^{12}$ Btu/yr

Gas = $(1.03 \times 10^{12}$ ft^3/yr$) \times (1000$ Btu/ft$^3) = 1030 \times 10^{12}$ Btu/yr

Total = 1860×10^{12} Btu/yr

Distribution by fuel type, percentage	
Coal	14
Residual oil	19
Distillate oil	12
Gas	55
	100

The split between residual oil (62 percent) and distillate oil (38 percent) was also used in subsequent calculations.

Application of these percentages to the total shown by the Walden boiler study yields the following:

No. of boilers (1,270,000)	
Coal	177,800
Residual oil	241,300
Distillate oil	152,400
Gas	698,500

Capacity (757×10^{12} Btu/h)		
Coal	(14%)	106.0
Residual oil	(19%)	143.8
Distillate oil	(12%)	90.8
Gas	(55%)	416.4

Since cast iron boilers are concentrated in two size categories, it is reasonable to assume that the boiler size distribution is the same for all fuels. The application of the percentages for fuel consumption to both boiler population and boiler capacity was based on this assumption.

The next step was to assemble data from the Hydronics Institute on cast iron boiler shipments from 1965 to 1975. The data were regrouped into the size categories used for the present study:

Hydronics Institute	Present study
200,000 to 249,999 Btu/h	$<0.4 \times 10^6$ Btu/h
250,000 to 449,999 Btu/h	$<0.4 \times 10^6$ Btu/h
450,000 to 949,999 Btu/h	0.4 to 1.5×10^6 Btu/h
950,000 to 1,549,999 Btu/h	0.4 to 1.5×10^6 Btu/h
>1,550,000 Btu/h	1.5 to 10×10^6 Btu/h

The assumption was made, based upon information from the Hydronics Institute, that 50 percent of the sales were replacement boilers. It was further assumed, on the basis of Walden field studies, that 80 percent of the nonresidential units were commercial boilers and 20 percent were industrial, and all boilers having capacity less than 200,000 Btu/h were residential units.

Table B-30 shows basic population data from the Hydronics Institute for boilers of more than 200,000 Btu/h capacity, adjusted downward to reflect the 50 percent for replacement boilers. Capacity was calculated on the assumption that the midpoint of the range was equal to the average size, except for boilers of more than 1,550,000 Btu/h capacity, which were assumed to have an average size of 3,400,000 Btu/h.

These calculations are illustrated for oil-fired boilers in the 1.5 to 10×10^6 Btu/h category:

Included sizes, Btu/h	Sales, No. of boilers	Average size, Btu/h	Capacity, Btu/h
1,550,000 and over	8,040	3,400,000	27,336,000,000

TABLE B-30. SUMMARY OF THE HYDRONICS INSTITUTE SALES DATA FOR INDUSTRIAL/COMMERCIAL CAST IRON BOILERS FOR 1965-1975 (ADJUSTED BY 50%)

Size range, 10^6 Btu/h	Fuel								Total	
	Stoker coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
<0.4	1,277	342	39,489	11,026	24,203	6,758	72,261	19,691	137,230	37,817
>0.4 to 1.5	530	705	13,704	11,753	8,399	7,204	30,219	26,019	52,852	45,681
>1.5 to 10.0	222	755	4,985	16,948	3,055	10,388	8,146	27,696	16,408	55,787
Total	2,029	1,802	58,178	39,727	35,657	24,350	110,626	73,406	206,490	139,285

The residual oil and distillate oil capacities were derived on the basis of the 62 percent and 38 percent figures from the Walden boiler study.

Table B-31 shows the number of boilers and the capacity data from the Walden boiler study, distributed by size and fuel type, using the following ratios derived from Hydronics Institute sales data.

Percentage Distribution of Cast Iron
Boilers from Sales Data (1965-1975)

	Size range					
	<0.4		0.4 to 1.5		1.5 to 10	
Fuel	Number, percent	Capacity, percent	Number, percent	Capacity, percent	Number, percent	Capacity, percent
Coal	63	19	26	39	11	42
Residual oil	68	28	24	30	8	42
Distillate oil	68	28	24	30	8	42
Gas	65	27	27	35	8	38

Average cast iron boiler size derived from Walden data:

$$\frac{757 \times 10^9 \text{ Btu/h}}{1,270 \times 10^3} \; 0.596 \text{ Btu/h}$$

Average cast iron boiler size derived from Hydronics Institute data:

$$\frac{139 \times 10^9 \text{ Btu/h}}{207 \times 10^3} = 0.671 \text{ Btu/h}$$

Reasonable comparison suggests that there has been no great shift in size distribution.

In Table B-32, data from B-30 and B-31 are combined to give the present estimate for all cast iron boilers.

In Tables B-33 and B-34, data from B-32 are divided to reflect the 80 percent commercial and 20 percent industrial usage.

TABLE B-31. DISTRIBUTION OF INDUSTRIAL/COMMERCIAL CAST IRON BOILER POPULATION (1967)

Size range, 10^6 Btu/h	Fuel								Total	
	Stoker coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
<0.4	112,010	20,140	164,080	40,260	103,630	25,420	454,030	112,430	833,750	198,250
>0.4 to 1.5	46,230	41,340	57,910	43,140	36,580	27,240	188,600	145,740	329,320	257,460
>1.5 to 10.0	19,560	44,520	19,300	60,400	12,190	38,140	55,880	158,230	106,930	301,290
Total	177,800	106,000	241,290	143,800	152,400	90,800	698,570	416,400	1,270,000	757,000

[a] Walden, 1971.

TABLE B-32. DISTRIBUTION OF TOTAL CAST IRON BOILER POPULATION BY FUEL (1977)

Size range, 10^6 Btu/h	Fuel								Total	
	Stoker coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
<0.4	113,287	20,500	203,569	51,300	127,833	32,200	526,291	132,100	970,980	236,100
>0.4 to 1.5	46,760	42,000	71,614	54,900	44,979	34,400	218,819	171,800	382,172	303,100
>1.5 to 10.0	19,782	45,300	24,285	77,300	15,245	48,500	64,026	185,900	123,338	357,000
Total	179,829	107,800	299,468	183,500	188,057	115,100	809,136	489,800	1,476,490	896,200

TABLE B-33. DISTRIBUTION OF THE COMMERCIAL/INSTITUTIONAL CAST IRON BOILER POPULATION (1977)

Size range, 10^6 Btu/h	Fuel								Total	
	Stoker coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
<0.4	90,630	16,400	162,855	41,000	102,266	25,700	421,033	105,700	776,784	188,800
>0.4 to 1.5	37,408	33,600	57,291	43,900	35,983	27,600	175,055	137,400	305,737	242,500
>1.5 to 10.0	15,826	36,200	19,428	61,900	12,196	38,800	51,221	148,700	98,671	285,600
Total	143,864	86,200	239,574	186,800	150,445	92,100	98,671	285,600	1,181,192	716,900

TABLE B-34. DISTRIBUTION OF THE INDUSTRIAL CAST IRON BOILER POPULATION (1977)

Size range, 10^6 Btu/h	Fuel								Total	
	Stoker coal		Residual oil		Distillate oil		Natural gas			
	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity	No.	Capacity
<0.4	22,657	4,100	40,714	10,300	25,567	6,400	105,258	26,400	194,196	47,200
>0.4 to 1.5	9,352	8,400	14,323	11,000	8,996	6,900	43,764	34,400	76,435	60,700
>1.5 to 10.0	3,956	9,100	4,857	15,500	3,049	9,700	12,805	37,200	24,667	71,500
Totals	35,965	21,600	59,894	36,800	37,612	23,000	161,827	98,000	295,298	179,400

APPENDIX C

DETAILED BOILER POPULATION DATA SHEETS

This appendix presents detailed summaries of the population of industrial and commercial boilers that were in place in 1977. The tables, which give data on the important characteristics of the boiler population, are organized in the following manner:

Information	Table No.
Total Industrial/Commercial Boiler Population	C-1
Total Water-tube Boiler Population	C-2
Distribution of the Field-erected Water-tube Boiler Population	C-3 through C-9
Distribution of the Package Water-tube Boiler Population	C-10 through C-16
Total Fire-tube Boiler Population	C-17
Total Fire-tube Boiler Population by Fuel	C-18 through C-21
Distribution of the Fire-tube Boiler Population by Fuel by Type	C-22 through C-37
Total Cast Iron Boiler Population	C-38
Total Cast Iron Boiler Population by Fuel	C-39 through C-42
Distribution of the Commercial Water-tube Boiler Population	C-43 through C-49
Distribution of the Commercial Fire-tube Boiler Population	C-50 through C-65
Distribution of the Commercial Cast Iron Boiler Population	C-66 through C-69
Distribution of the Industrial Water-tube Boiler Population	C-70 through C-76
Distribution of the Industrial Fire-tube Boiler Population	C-77 through C-92
Distribution of the Industrial Cast Iron Boiler Population	C-93 through C-96

Table C-1. THE 1977 POPULATION OF INDUSTRIAL/COMMERCIAL BOILERS

Boiler classification: All types of boilers

Fuel and firing mechanism: All fuels

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,802,060	1,313,340 (4,482,230)
Distribution by heat-transfer medium		
Supercritical steam		
Steam (high-pressure)		
Steam (low-pressure)		
Hot water		
Distribution by usage		
Commercial-institutional	1,295,130	402,765 (1,374,690)
Industrial	506,930	910,575 (3,107,440)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	970,980	69,180 (236,100)
Over 0.1 to 0.4 (0.4 to 1.5)	568,415	143,820 (490,730)
Over 0.4 to 2.9 (1.5 to 10)	208,659	240,270 (820,100)
Over 2.9 to 7.3 (10 to 25)	[illegible],081	126,770 (432,600)
Over 7.3 to 14.7 (25 to 50)	16,483	178,350 (608,700)
Over 14.7 to 29.3 (50 to 100)	6,840	147,380 (503,000)
Over 29.3 to 73.3 (100 to 250)	4,266	185,160 (632,000)
Over 73.3 to 146.5 (250 to 500)	1,018	98,280 (335,400)
Over 146.5 to 439.5 (500 to 1500)	253	56,080 (191,400)
Over 439.5 (1500)	65	68,050 (232,200)

Table C-2. THE 1977 POPULATION OF INDUSTRIAL/COMMERCIAL WATER-TUBE BOILERS

Boiler classification: Water-tube

Fuel and firing mechanism: All fuels

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	50,495	747,930 (2,552,530)
Distribution by heat-transfer medium		
Supercritical steam		
Steam (high-pressure)		
Steam (low-pressure)		
Hot water		
Distribution by usage		
Commercial-institutional	12,799	109,285 (372,990)
Industrial	37,696	638,645 (2,179,540)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	7,075	2,450 (8,330)
Over 0.4 to 2.9 (1.5 to 10)	10,934	14,950 (51,000)
Over 2.9 to 7.3 (10 to 25)	6,813	32,980 (112,500)
Over 7.3 to 14.7 (25 to 50)	13,231	142,600 (486,700)
Over 14.7 to 29.3 (50 to 100)	6,840	147,380 (503,000)
Over 29.3 to 73.3 (100 to 250)	4,266	185,160 (632,000)
Over 73.3 to 146.5 (250 to 500)	1,018	98,280 (335,400)
Over 146.5 to 439.5 (500 to 1500)	253	56,080 (191,400)
Over 439.5 (1500)	65	68,050 (232,200)

TABLE C-3. THE 1977 POPULATION OF FIELD-ERECTED WATER-TUBE BOILERS FIRING PULVERIZED COAL

Boiler classification: Water-tube (field-erected)

Fuel and firing mechanism: Pulverized coal

	Number	Capacity, thermal MW (10^6 Btu/h)	
Class population	615	55,470	(189,300)
Distribution by heat-transfer medium			
Supercritical steam	12	1,110	(3,800)
Steam (high-pressure)	603	54,360	(185,500)
Steam (low-pressure)	0		
Hot water	0		
Distribution by usage			
Commercial-institutional (space heating)	10	460	(1,600)
Industrial (space heating)	101	9,280	(31,700)
Industrial (process heat)	504	45,730	(156,000)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	0		
Over 0.1 to 0.4 (0.4 to 1.5)	0		
Over 0.4 to 2.9 (1.5 to 10)	0		
Over 2.9 to 7.3 (10 to 25)	0		
Over 7.3 to 14.7 (25 to 50)	0		
Over 14.7 to 29.3 (50 to 100)	0		
Over 29.3 to 73.3 (100 to 250)	350	15,380	(52,500)
Over 73.3 to 146.5 (250 to 500)	190	18,370	(62,700)
Over 146.5 to 439.5 (500 to 1500)	64	13,980	(47,700)
Over 439.5 (1500)	11	7,740	(26,400)

TABLE C-4. THE 1977 POPULATION OF FIELD-ERECTED WATER-TUBE BOILERS FIRING COAL (SPREADER STOKER)

Boiler classification: Water-tube (field-erected)

Fuel and firing mechanism: Coal, spreader-stoker

	Number	Capacity, thermal MW	(10^6 Btu/h)
Class population	793	32,300	(110,200)
Distribution by heat-transfer medium			
Supercritical steam	0		
Steam (high-pressure)	135	5,490	(18,700)
Steam (low-pressure)	626	25,520	(87,100)
Hot water	32	1,290	(4,400)
Distribution by usage			
Commercial-institutional (space heating)	110	2,570	(8,800)
Industrial (space heating)	165	7,190	(24,500)
Industrial (process heat)	518	22,520	(76,900)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	0		
Over 0.1 to 0.4 (0.4 to 1.5)	0		
Over 0.4 to 2.9 (1.5 to 10)	0		
Over 2.9 to 7.3 (10 to 25)	43	210	(700)
Over 7.3 to 14.7 (25 to 50)	157	1,760	(6,000)
Over 14.7 to 29.3 (50 to 100)	120	2,610	(8,900)
Over 29.3 to 73.3 (100 to 250)	379	16,200	(55,300)
Over 73.3 to 146.5 (250 to 500)	82	7,410	(25,300)
Over 146.5 to 439.5 (500 to 1500)	9	2,260	(7,700)
Over 439.5 (1500)	3	1,850	(6,300)

TABLE C-5. THE 1977 POPULATION OF FIELD-ERECTED WATER-TUBE BOILERS FIRING COAL (OVERFEED STOKER)

Boiler classification: Water-tube (field-erected)

Fuel and firing mechanism: Coal, overfeed-stoker

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	329	9,770 (33,300)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	56	1,660 (5,700)
Steam (low-pressure)	260	7,720 (26,300)
Hot water	13	390 (1,300)
Distribution by usage		
Commercial-institutional (space heating)	65	1,090 (3,700)
Industrial (space heating)	80	2,620 (9,000)
Industrial (process heat)	184	6,060 (20,600)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	0	
Over 0.4 to 2.9 (1.5 to 10)	0	
Over 2.9 to 7.3 (10 to 25)	26	120 (400)
Over 7.3 to 14.7 (25 to 50)	120	1,320 (4,500)
Over 14.7 to 29.3 (50 to 100)	87	1,880 (6,400)
Over 29.3 to 73.3 (100 to 250)	67	2,840 (9,700)
Over 73.3 to 146.5 (250 to 500)	25	2,260 (7,700)
Over 146.5 to 439.5 (500 to 1500)	3	730 (2,500)
Over 439.5 (1500)	1	620 (2,100)

TABLE C-6. THE 1977 POPULATION OF FIELD-ERECTED WATER-TUBE BOILERS FIRING COAL (UNDERFEED STOKER)

Boiler classification: Water-tube (field-erected)

Fuel and firing mechanism: Coal, underfeed-stoker

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,161	24,550 (83,800)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	197	4,170 (14,200)
Steam (low-pressure)	917	19,390 (66,200)
Hot water	47	980 (3,400)
Distribution by usage		
Commercial-institutional (space heating)	268	3,650 (12,400)
Industrial (space heating)	236	5,570 (19,000)
Industrial (process heat)	657	15,330 (52,400)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	0	
Over 0.4 to 2.9 (1.5 to 10)	0	
Over 2.9 to 7.3 (10 to 25)	197	970 (3,300)
Over 7.3 to 14.7 (25 to 50)	453	5,040 (17,200)
Over 14.7 to 29.3 (50 to 100)	333	7,470 (25,500)
Over 29.3 to 73.3 (100 to 250)	135	5,650 (19,300)
Over 73.3 to 146.5 (250 to 500)	37	3,400 (11,600)
Over 146.5 to 439.5 (500 to 1500)	5	1,110 (3,800)
Over 439.5 (1500)	1	910 (3,100)

TABLE C-7. THE 1977 POPULATION OF FIELD-ERECTED WATER-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Water-tube (field-erected)

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW	(10^6 Btu/h)
Class population	4,393	125,060	(426,800)
Distribution by heat-transfer medium			
Supercritical steam	88	2,500	(8,500)
Steam (high-pressure)	4,305	122,560	(418,300)
Steam (low-pressure)	0		
Hot water	0		
Distribution by usage			
Commercial-institutional (space heating)	1,120	20,940	(76,300)
Industrial (space heating)	573	17,720	(66,200)
Industrial (process heat)	2,801	64,070	(322,000)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	0		
Over 0.1 to 0.4 (0.4 to 1.5)	0		
Over 0.4 to 2.9 (1.5 to 10)	0		
Over 2.9 to 7.3 (10 to 25)	819	3,900	(13,300)
Over 7.3 to 14.7 (25 to 50)	1,507	16,060	(54,800)
Over 14.7 to 29.3 (50 to 100)	771	16,640	(56,800)
Over 29.3 to 73.3 (100 to 250)	928	39,990	(136,500)
Over 73.3 to 146.5 (250 to 500)	298	28,950	(98,800)
Over 146.5 to 439.5 (500 to 1500)	62	13,890	(47,400)
Over 439.5 (1500)	8	5,630	(19,200)

TABLE C-8. THE 1977 POPULATION OF FIELD-ERECTED WATER-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Water-tube (field-erected)

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	775	18,970 (64,800)
Distribution by heat-transfer medium		
Supercritical steam	15	380 (1,300)
Steam (high-pressure)	760	18,590 (63,500)
Steam (low-pressure)	0	
Hot water	0	
Distribution by usage		
Commercial-institutional (space heating)	250	6,190 (21,100)
Industrial (space heating)	89	2,160 (7,300)
Industrial (process heat)	436	10,620 (36,400)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	0	
Over 0.4 to 2.9 (1.5 to 10)	0	
Over 2.9 to 7.3 (10 to 25)	197	880 (3,000)
Over 7.3 to 14.7 (25 to 50)	274	2,780 (9,500)
Over 14.7 to 29.3 (50 to 100)	105	2,340 (8,000)
Over 29.3 to 73.3 (100 to 250)	151	6,620 (22,600)
Over 73.3 to 146.5 (250 to 500)	40	4,160 (14,200)
Over 146.5 to 439.5 (500 to 1500)	7	1,520 (5,200)
Over 439.5 (1500)	1	670 (2,300)

TABLE C-9. THE 1977 POPULATION OF FIELD-ERECTED WATER-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Water-tube (field-erected)

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	4,867	198,530 (677,600)
Distribution by heat-transfer medium		
Supercritical steam	98	4,000 (13,600)
Steam (high-pressure)	4,769	194,530 (664,000)
Steam (low-pressure)	0	
Hot water	0	
Distribution by usage		
Commercial-institutional (space heating)	512	19,400 (66,100)
Industrial (space heating)	732	30,230 (103,000)
Industrial (process heat)	3,623	148,900 (508,500)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	0	
Over 0.4 to 2.9 (1.5 to 10)	0	
Over 2.9 to 7.3 (10 to 25)	760	3,780 (12,900)
Over 7.3 to 14.7 (25 to 50)	1,459	15,820 (54,000)
Over 14.7 to 29.3 (50 to 100)	979	20,830 (71,100)
Over 29.3 to 73.3 (100 to 250)	1,189	52,180 (178,100)
Over 73.3 to 146.5 (250 to 500)	337	32,700 (111,600)
Over 146.5 to 439.5 (500 to 1500)	103	22,590 (77,100)
Over 439.5 (1500)	40	50,630 (172,800)

TABLE C-10. THE 1977 POPULATION OF PACKAGE WATER-TUBE BOILERS FIRING PULVERIZED COAL

Boiler classification: Water-tube (package)

Fuel and firing mechanism: Pulverized coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	118	5,220 (17,800)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	20	890 (3,000)
Steam (low-pressure)	93	4,120 (14,100)
Hot water	5	210 (700)
Distribution by usage		
Commercial-institutional (space heating)	4	150 (500)
Industrial (space heating)	31	1,420 (4,800)
Industrial (process heat)	83	3,650 (12,500)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	0	
Over 0.4 to 2.9 (1.5 to 10)	0	
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	117	5,130 (17,500)
Over 73.3 to 146.5 (250 to 500)	1	90 (300)
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-11. THE 1977 POPULATION OF PACKAGE WATER-TUBE BOILERS FIRING COAL (SPREADER STOKER)

Boiler classification: Water-tube (package)

Fuel and firing mechanism: Coal, spreader-stoker

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	915	15,030 (51,300)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	156	2,555 (8,721)
Steam (low-pressure)	723	11,874 (40,527)
Hot water	36	601 (2,052)
Distribution by usage		
Commercial-institutional (space heating)	477	2,520 (8,600)
Industrial (space heating)	342	3,250 (11,100)
Industrial (process heat)	96	9,260 (31,600)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	0	
Over 0.4 to 2.9 (1.5 to 10)	103	150 (500)
Over 2.9 to 7.3 (10 to 25)	99	500 (1,700)
Over 7.3 to 14.7 (25 to 50)	364	4,070 (13,900)
Over 14.7 to 29.3 (50 to 100)	223	4,830 (16,500)
Over 29.3 to 73.3 (100 to 250)	125	5,390 (18,400)
Over 73.3 to 146.5 (250 to 500)	1	90 (300)
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-12. THE 1977 POPULATION OF PACKAGE WATER-TUBE BOILERS FIRING COAL (OVERFEED STOKER)

Boiler classification: Water-tube (package)

Fuel and firing mechanism: Coal, overfeed-stoker

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	673	8,140 (27,730)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	118	1,390 (4,730)
Steam (low-pressure)	527	6,420 (21,890)
Hot water	28	330 (1,110)
Distribution by usage		
Commercial-institutional (space heating)	213	1,750 (5,970)
Industrial (space heating)	122	1,680 (5,800)
Industrial (process heat)	338	4,710 (15,960)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	28	10 (30)
Over 0.4 to 2.9 (1.5 to 10)	114	180 (600)
Over 2.9 to 7.3 (10 to 25)	63	320 (1,100)
Over 7.3 to 14.7 (25 to 50)	282	3,110 (10,600)
Over 14.7 to 29.3 (50 to 100)	162	3,490 (11,900)
Over 29.3 to 73.3 (100 to 250)	23	940 (3,200)
Over 73.3 to 146.5 (250 to 500)	1	90 (300)
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-13. THE 1977 POPULATION OF PACKAGE WATER-TUBE BOILERS FIRING COAL (UNDERFEED STOKER)

Boiler classification: Water-tube (package)

Fuel and firing mechanism: Coal, underfeed-stoker

	Number	Capacity, thermal MW	(10^6 Btu/h)
Class population	3,639	30,840	(105,200)
Distribution by heat-transfer medium			
Supercritical steam	0		
Steam (high-pressure)	619	5,240	(17,880)
Steam (low-pressure)	2,875	24,360	(83,100)
Hot water	145	1,240	(4,220)
Distribution by usage			
Commercial-institutional (space heating)	1,460	7,400	(25,250)
Industrial (space heating)	578	6,090	(20,780)
Industrial (process heat)	1,601	17,350	(59,170)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	0		
Over 0.1 to 0.4 (0.4 to 1.5)	532	150	(500)
Over 0.4 to 2.9 (1.5 to 10)	928	1,410	(4,800)
Over 2.9 to 7.3 (10 to 25)	460	2,260	(7,700)
Over 7.3 to 14.7 (25 to 50)	1,056	11,720	(40,000)
Over 14.7 to 29.3 (50 to 100)	617	13,330	(45,500)
Over 29.3 to 73.3 (100 to 250)	45	1,880	(6,400)
Over 73.3 to 146.5 (250 to 500)	1	90	(300)
Over 146.5 to 439.5 (500 to 1500)	0		
Over 439.5 (1500)	0		

TABLE C-14. THE 1977 POPULATION OF PACKAGE WATER-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Water-tube (package)

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	11,560	96,350 (328,900)
Distribution by heat-transfer medium		
Supercritical steam	231	1,930 (6,580)
Steam (high-pressure)	11,329	94,420 (322,320)
Steam (low-pressure)	0	
Hot water	0	
Distribution by usage		
Commercial-institutional (space heating)	3,061	24,060 (82,180)
Industrial (space heating)	1,447	12,290 (41,960)
Industrial (process heat)	7,052	60,000 (204,760)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,173	410 (1,400)
Over 0.4 to 2.9 (1.5 to 10)	3,215	4,830 (16,500)
Over 2.9 to 7.3 (10 to 25)	1,912	9,110 (31,100)
Over 7.3 to 14.7 (25 to 50)	3,515	37,500 (128,000)
Over 14.7 to 29.3 (50 to 100)	1,434	30,880 (105,400)
Over 29.3 to 73.3 (100 to 250)	309	13,330 (45,500)
Over 73.3 to 146.5 (250 to 500)	2	290 (1,000)
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-15. THE 1977 POPULATION OF PACKAGE WATER-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Water-tube (package)

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	7,223	19,790 (67,500)
Distribution by heat-transfer medium		
Supercritical steam	144	400 (1,400)
Steam (high-pressure)	7,079	19,390 (66,100)
Steam (low-pressure)	0	
Hot water	0	
Distribution by usage		
Commercial-institutional (space heating)	3,173	6,960 (23,800)
Industrial (space heating)	753	2,450 (8,300)
Industrial (process heat)	3,297	10,380 (35,400)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	2,928	1,030 (3,500)
Over 0.4 to 2.9 (1.5 to 10)	2,958	3,460 (11,800)
Over 2.9 to 7.3 (10 to 25)	462	2,080 (7,100)
Over 7.3 to 14.7 (25 to 50)	640	6,530 (22,300)
Over 14.7 to 29.3 (50 to 100)	193	4,370 (14,900)
Over 29.3 to 73.3 (100 to 250)	51	2,230 (7,600)
Over 73.3 to 146.5 (250 to 500)	1	90 (300)
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-16. THE 1977 POPULATION OF PACKAGE WATER-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Water-tube (package)

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)	
Class population	13,424	107,910	(368,300)
Distribution by heat-transfer medium			
Supercritical steam	268	2,160	(7,370)
Steam (high-pressure)	13,156	105,750	(360,930)
Steam (low-pressure)	0		
Hot water	0		
Distribution by usage			
Commercial-institutional (space heating)	2,439	11,960	(40,800)
Industrial (space heating)	1,881	16,110	(55,000)
Industrial (process heat)	9,104	79,840	(272,500)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	0		
Over 0.1 to 0.4 (0.4 to 1.5)	2,414	850	(2,900)
Over 0.4 to 2.9 (1.5 to 10)	3,616	4,920	(16,800)
Over 2.9 to 7.3 (10 to 25)	1,775	8,850	(30,200)
Over 7.3 to 14.7 (25 to 50)	3,404	36,890	(125,900)
Over 14.7 to 29.3 (50 to 100)	1,816	38,710	(132,100)
Over 29.3 to 73.3 (100 to 250)	397	17,400	(59,400)
Over 73.3 to 146.5 (250 to 500)	2	290	(1,000)
Over 146.5 to 439.5 (500 to 1500)	0		
Over 439.5 (1500)	0		

Table C-17. THE 1977 POPULATION OF INDUSTRIAL/COMMERCIAL FIRE-TUBE BOILERS

Boiler classification: Fire-tube boilers

Fuel and firing mechanism: All fuels

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	275,075	302,780 (1,033,300)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	145,788	160,435 (547,556)
Steam (low-pressure)	68,771	75,680 (258,282)
Hot water	60,516	66,665 (227,462)
Distribution by usage		
Commercial-institutional	101,139	83,420 (284,800)
Industrial	173,936	219,360 (748,500)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	179,168	52,520 (179,200)
Over 0.4 to 2.9 (1.5 to 10)	74,387	120,720 (412,000)
Over 2.9 to 7.3 (10 to 25)	18,268	93,790 (320,100)
Over 7.3 to 14.7 (25 to 50)	3,252	35,750 (122,000)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-18. THE 1977 POPULATION OF FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	26,328	26,201 (89,430)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	13,954	13,886 (47,397)
Steam (low-pressure)	6,583	6,551 (22,358)
Hot water	5,791	5,764 (19,675)
Distribution by usage		
Commercial-institutional (space heating)	16,993	12,778 (43,617)
Industrial (space heating)	9,335	13,423 (45,813)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	19,227	5,632 (19,227)
Over 0.4 to 2.9 (1.5 to 10)	5,210	8,778 (29,959)
Over 2.9 to 7.3 (10 to 25)	1,533	7,860 (26,829)
Over 7.3 to 14.7 (25 to 50)	358	3,931 (13,415)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-19. THE 1977 POPULATION OF FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	73,683	83,388 (284,596)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	39,051	44,195 (150,836)
Steam (low-pressure)	18,421	20,847 (71,149)
Hot water	16,211	18,345 (62,611)
Distribution by usage		
Commercial-institutional (space heating)	22,445	22,256 (77,339)
Industrial (space heating)	51,238	61,132 (207,257)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	46,267	13,555 (46,263)
Over 0.4 to 2.9 (1.5 to 10)	21,511	34,634 (118,204)
Over 2.9 to 7.3 (10 to 25)	5,072	26,051 (88,910)
Over 7.3 to 14.7 (25 to 50)	833	9,148 (31,219)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

Table C-20. THE 1977 POPULATION OF FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	48,141	54,560 (186,200)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	25,514	28,895 (98,633)
Steam (low-pressure)	12,036	13,631 (46,525)
Hot water	10,591	11,994 (40,942)
Distribution by usage		
Commercial-institutional	22,845	21,187 (71,709)
Industrial	25,296	33,373 (114,491)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	30,191	8,850 (30,200)
Over 0.4 to 2.9 (1.5 to 10)	14,089	22,680 (77,400)
Over 2.9 to 7.3 (10 to 25)	3,318	17,050 (58,200)
Over 7.3 to 14.7 (25 to 50)	543	5,980 (20,400)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

Table C-21. THE 1977 POPULATION OF FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	126,923	138,630 (473,100)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	67,269	73,459 (250,690)
Steam (low-pressure)	31,731	34,651 (118,250)
Hot water	27,923	30,472 (104,060)
Distribution by usage		
Commercial-institutional	38,856	27,375 (93,440)
Industrial	88,067	111,255 (379,660)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	83,483	24,470 (83,500)
Over 0.4 to 2.9 (1.5 to 10)	33,577	54,620 (186,400)
Over 2.9 to 7.3 (10 to 25)	8,345	42,840 (146,200)
Over 7.3 to 14.7 (25 to 50)	1,518	16,700 (57,000)
Over 14.7 to 29.3 (50 to 100)		
Over 29.3 to 73.3 (100 to 250)		
Over 73.3 to 146.5 (250 to 500)		
Over 146.5 to 439.5 (500 to 1500)		
Over 439.5 (1500)		

TABLE C-22. THE 1977 POPULATION OF SCOTCH FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (Scotch)

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	8,591	9,780 (33,379)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	4,553	5,183 (17,691)
Steam (low-pressure)	2,148	2,445 (8,345)
Hot water	1,890	2,152 (7,343)
Distribution by usage		
Commercial-institutional (space heating)	5,468	4,593 (15,678)
Industrial (space heating)	3,123	5,187 (17,701)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	5,960	1,746 (5,960)
Over 0.1 to 0.4 (0.4 to 1.5)	1,876	3,160 (10,785)
Over 0.4 to 2.9 (1.5 to 10)	583	2,987 (10,195)
Over 2.9 to 7.3 (10 to 25)	172	1,887 (6,439)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-23. THE 1977 POPULATION OF FIREBOX FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (firebox)

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	12,745	10,842 (37,006)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	6,755	5,746 (19,613)
Steam (low-pressure)	3,186	2,711 (9,252)
Hot water	2,804	2,385 (8,141)
Distribution by usage		
Commercial-institutional (space heating)	8,375	5,440 (18,569)
Industrial (space heating)	4,370	5,402 (18,437)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	9,998	2,929 (9,998)
Over 0.4 to 2.9 (1.5 to 10)	2,084	3,511 (11,984)
Over 2.9 to 7.3 (10 to 25)	491	2,515 (8,585)
Over 7.3 to 14.7 (25 to 50)	172	1,887 (6,439)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-24. THE 1977 POPULATION OF HRT FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (HRT)

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	3,274	4,344 (14,289)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	1,735	2,302 (7,859)
Steam (low-pressure)	819	1,086 (3,707)
Hot water	720	956 (3,263)
Distribution by usage		
Commercial-institutional (space heating)	2,014	2,063 (7,043)
Industrial (space heating)	1,260	2,281 (7,246)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,923	563 (1,923)
Over 0.4 to 2.9 (1.5 to 10)	938	1,580 (5,393)
Over 2.9 to 7.3 (10 to 25)	399	2,044 (6,976)
Over 7.3 to 14.7 (25 to 50)	14	157 (537)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-25. THE 1977 POPULATION OF OTHER FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (other)

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,718	1,235 (4,216)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	911	655 (2,234)
Steam (low-pressure)	430	309 (1,054)
Hot water	377	271 (928)
Distribution by usage		
Commercial-institutional (space heating)	1,136	682 (2,327)
Industrial (space heating)	582	553 (1,889)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,346	394 (1,346)
Over 0.4 to 2.9 (1.5 to 10)	312	527 (1,797)
Over 2.9 to 7.3 (10 to 25)	60	314 (1,073)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-26. THE 1977 POPULATION OF SCOTCH FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (Scotch)

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h).	
Class population	25,997	34,152	(116,558)
Distribution by heat-transfer medium			
Supercritical steam	0		
Steam (high-pressure)	13,778	18,100	(61,776)
Steam (low-pressure)	6,499	8,538	(29,140)
Hot water	5,720	7,513	(25,642)
Distribution by usage			
Commercial-institutional (space heating)	7,729	9,010	(30,753)
Industrial (space heating)	18,268	25,142	(85,805)
Industrial (process heat)	0		
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	0		
Over 0.1 to 0.4 (0.4 to 1.5)	14,311	4,192	(14,310)
Over 0.4 to 2.9 (1.5 to 10)	9,151	14,599	(49,825)
Over 2.9 to 7.3 (10 to 25)	2,135	10,970	(37,438)
Over 7.3 to 14.7 (25 to 50)	400	4,391	(14,985)
Over 14.7 to 29.3 (50 to 100)	0		
Over 29.3 to 73.3 (100 to 250)	0		
Over 73.3 to 146.5 (250 to 500)	0		
Over 146.5 to 439.5 (500 to 1500)	0		
Over 439.5 (1500)	0		

TABLE C-27. THE 1977 POPULATION OF FIREBOX FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (firebox)

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	35,030	35,056 (119,645)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	18,566	18,580 (63,412)
Steam (low-pressure)	8,758	8,764 (29,911)
Hot water	7,706	7,712 (26,322)
Distribution by usage		
Commercial-institutional (space heating)	10,859	9,482 (33,744)
Industrial (space heating)	24,171	25,574 (85,901)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	23,989	7,028 (23,987)
Over 0.4 to 2.9 (1.5 to 10)	8,792	14,138 (48,251)
Over 2.9 to 7.3 (10 to 25)	1,849	9,499 (32,422)
Over 7.3 to 14.7 (25 to 50)	400	4,391 (14,985)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-28. THE 1977 POPULATION OF HRT FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (HRT)

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	7,680	9,887 (33,744)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	4,070	5,240 (17,884)
Steam (low-pressure)	1,920	2,472 (8,436)
Hot water	1,690	2,175 (7,424)
Distribution by usage		
Commercial-institutional (space heating)	2,309	2,600 (8,871)
Industrial (space heating)	5,371	7,287 (24,873)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	4,475	1,311 (4,475)
Over 0.4 to 2.9 (1.5 to 10)	2,277	3,819 (13,035)
Over 2.9 to 7.3 (10 to 25)	928	4,757 (16,234)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-29. THE 1977 POPULATION OF OTHER FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (other)

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	4,976	4,293 (14,649)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	2,637	2,275 (7,764)
Steam (low-pressure)	1,244	1,073 (3,662)
Hot water	1,095	945 (3,223)
Distribution by usage		
Commercial-institutional (space heating)	1,548	1,164 (3,971)
Industrial (space heating)	3,428	3,129 (10,678)
Industrial (process heat)		
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	3,492	1,024 (3,491)
Over 0.4 to 2.9 (1.5 to 10)	1,291	2,078 (7,093)
Over 2.9 to 7.3 (10 to 25)	160	825 (2,816)
Over 7.3 to 14.7 (25 to 50)	33	366 (1,249)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-30. THE 1977 POPULATON OF SCOTCH FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (Scotch)

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	16,995	22,340 (76,300)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	9,007	11,840 (40,439)
Steam (low-pressure)	4,249	5,585 (19,075)
Hot water	3,739	4,915 (16,786)
Distribution by usage		
Commercial-institutional (space heating)	7,868	8,445 (28,838)
Industrial (space heating)	9,127	13,895 (47,462)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	9,338	2,730 (9,300)
Over 0.4 to 2.9 (1.5 to 10)	5,999	9,570 (32,700)
Over 2.9 to 7.3 (10 to 25)	1,397	7,180 (24,500)
Over 7.3 to 14.7 (25 to 50)	261	2,860 (9,800)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-31. THE 1977 POPULATION OF FIREBOX FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (firebox)

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h).
Class population	22,884	22,930 (78,300)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	12,129	12,153 (41,499)
Steam (low-pressure)	5,721	5,733 (19,575)
Hot water	5,034	5,044 (17,226)
Distribution by usage		
Commercial-institutional (space heating)	11,061	9,009 (30,767)
Industrial (space heating)	11,823	13,921 (47,533)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	15,653	4,590 (15,700)
Over 0.4 to 2.9 (1.5 to 10)	5,759	9,260 (31,600)
Over 2.9 to 7.3 (10 to 25)	1,211	6,220 (21,200)
Over 7.3 to 14.7 (25 to 50)	261	2,860 (9,800)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-32. THE 1977 POPULATION OF HRT FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (HRT)

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	5,031	6,680 (22,800)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	2,666	3,540 (12,084)
Steam (low-pressure)	1,258	1,670 (5,700)
Hot water	1,107	1,470 (5,016)
Distribution by usage		
Commercial-institutional (space heating)	2,336	2,667 (8,487)
Industrial (space heating)	2,695	4,013 (14,313)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	2,919	850 (2,900)
Over 0.4 to 2.9 (1.5 to 10)	1,486	2,490 (8,500)
Over 2.9 to 7.3 (10 to 25)	605	3,100 (10,600)
Over 7.3 to 14.7 (25 to 50)	21	240 (800)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-33. THE 1977 POPULATION OF OTHER FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (other)

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	3,231	2,570 (8,700)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	1,712	1,362 (4,611)
Steam (low-pressure)	808	643 (2,175)
Hot water	711	565 (1,914)
Distribution by usage		
Commercial-institutional (space heating)	1,580	1,066 (3,617)
Industrial (space heating)	1,651	1,504 (5,083)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	2,281	670 (2,300)
Over 0.4 to 2.9 (1.5 to 10)	845	1,360 (4,600)
Over 2.9 to 7.3 (10 to 25)	105	540 (1,800)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-34. THE 1977 POPULATION OF SCOTCH FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (Scotch)

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	43,800	55,430 (189,100)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	23,214	29,378 (100,223)
Steam (low-pressure)	10,950	13,858 (47,275)
Hot water	9,636	12,194 (41,602)
Distribution by usage		
Commercial-institutional (space heating)	12,847	10,421 (35,549)
Industrial (space heating)	30,953	45,009 (153,551)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	25,841	7,570 (25,800)
Over 0.4 to 2.9 (1.5 to 10)	13,806	22,260 (76,000)
Over 2.9 to 7.3 (10 to 25)	3,424	17,590 (60,000)
Over 7.3 to 14.7 (25 to 50)	729	8,010 (27,300)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-35. THE 1977 POPULATION OF FIREBOX FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (firebox)

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	60,661	58,020 (197,900)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	32,150	30,751 (104,887)
Steam (low-pressure)	15,165	14,505 (49,475)
Hot water	13,346	12,746 (43,538)
Distribution by usage		
Commercial-institutional (space heating)	19,226	11,981 (40,872)
Industrial (space heating)	41,435	46,039 (157,028)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	43,326	12,690 (43,300)
Over 0.4 to 2.9 (1.5 to 10)	13,660	22,190 (75,700)
Over 2.9 to 7.3 (10 to 25)	2,946	15,130 (51,600)
Over 7.3 to 14.7 (25 to 50)	729	8,010 (27,300)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-36. THE 1977 POPULATION OF HRT FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (HRT)

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	14,012	18,620 (63,600)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	7,426	9,869 (33,708)
Steam (low-pressure)	3,503	4,655 (15,900)
Hot water	3,083	4,096 (13,992)
Distribution by usage		
Commercial-institutional (space heating)	4,066	3,462 (11,835)
Industrial (space heating)	9,946	15,158 (51,765)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	8,163	2,390 (8,200)
Over 0.4 to 2.9 (1.5 to 10)	4,097	6,880 (23,500)
Over 2.9 to 7.3 (10 to 25)	1,692	8,680 (29,600)
Over 7.3 to 14.7 (25 to 50)	60	670 (2,300)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-37. THE 1977 POPULATION OF OTHER FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (other)

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW	(10^6 Btu/h)
Class population	8,450	6,350	(22,400)
Distribution by heat-transfer medium			
Supercritical steam	0		
Steam (high-pressure)	4,479	3,461	(11,872)
Steam (low-pressure)	2,113	1,633	(5,600)
Hot water	1,858	1,436	(4,928)
Distribution by usage			
Commercial-institutional (space heating)	2,717	1,511	(5,184)
Industrial (space heating)	5,733	4,839	(17,216)
Industrial (process heat)	0		
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	0		
Over 0.1 to 0.4 (0.4 to 1.5)	6,153	1,800	(6,200)
Over 0.4 to 2.9 (1.5 to 10)	2,014	3,280	(11,200)
Over 2.9 to 7.3 (10 to 25)	283	1,450	(5,000)
Over 7.3 to 14.7 (25 to 50)	0		
Over 14.7 to 29.3 (50 to 100)	0		
Over 29.3 to 73.3 (100 to 250)	0		
Over 73.3 to 146.5 (250 to 500)	0		
Over 146.5 to 439.5 (500 to 1500)	0		
Over 439.5 (1500)	0		

Table C-38. THE 1977 POPULATION OF INDUSTRIAL/COMMERCIAL CAST IRON BOILERS

Boiler classification: Cast iron

Fuel and firing mechanism: All fuels

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,476,490	262,600 (896,200)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	0	
Steam (low-pressure)	0	
Hot water	0	
Distribution by usage		
Commercial-institutional	1,181,192	210,060 (716,900)
Industrial	295,298	52,570 (179,400)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	970,980	69,180 (236,100)
Over 0.1 to 0.4 (0.4 to 1.5)	382,172	88,820 (303,100)
Over 0.4 to 2.9 (1.5 to 10)	123,338	104,600 (357,000)
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-39. 1977 POPULATION OF CAST IRON BOILERS FIRING COAL

Boiler classification: Cast iron

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10⁶ Btu/h)
Class population	179,829	31,586 (107,802)
Distribution by heat-transfer medium		
Supercritical steam	0	
Steam (high-pressure)	0	
Steam (low-pressure)	0	
Hot water	0	
Distribution by usage		
Commercial-institutional (space heating)	143,864	25,269 (86,242)
Industrial (space heating)	35,965	6,317 (21,560)
Industrial (process heat)	0	
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	113,287	6,001 (20,482)
Over 0.1 to 0.4 (0.4 to 1.5)	46,760	12,319 (42,045)
Over 0.4 to 2.9 (1.5 to 10)	19,782	13,266 (45,275)
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-40. 1977 POPULATION OF CAST IRON BOILERS FIRING RESIDUAL OIL

Boiler classification: Cast iron

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW	(10^6 Btu/h)
Class population	299,468	53,774	(183,527)
Distribution by heat-transfer medium			
Supercritical steam	0		
Steam (high-pressure)	0		
Steam (low-pressure)	0		
Hot water	0		
Distribution by usage			
Commercial-institutional (space heating)	239,574	43,019	(146,821)
Industrial (space heating)	59,894	10,755	(36,706)
Industrial (process heat)	0		
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	203,569	15,027	(51,286)
Over 0.1 to 0.4 (0.4 to 1.5)	71,614	16,084	(54,893)
Over 0.4 to 2.9 (1.5 to 10)	24,285	22,663	(77,348)
Over 2.9 to 7.3 (10 to 25)	0		
Over 7.3 to 14.7 (25 to 50)	0		
Over 14.7 to 29.3 (50 to 100)	0		
Over 29.3 to 73.3 (100 to 250)	0		
Over 73.3 to 146.5 (250 to 500)	0		
Over 146.5 to 439.5 (500 to 1500)	0		
Over 439.5 (1500)	0		

TABLE C-41. 1977 POPULATION OF CAST IRON BOILERS FIRING DISTILLATE OIL

Boiler classification: Cast iron

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)	
Class population	188,057	33,739	(115,150)
Distribution by heat-transfer medium			
Supercritical steam	0		
Steam (high-pressure)	0		
Steam (low-pressure)	0		
Hot water	0		
Distribution by usage			
Commercial-institutional (space heating)	150,455	26,991	(92,119)
Industrial (space heating)	37,612	6,748	(23,031)
Industrial (process heat)	0		
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	127,833	9,428	(32,178)
Over 0.1 to 0.4 (0.4 to 1.5)	44,979	10,092	(34,444)
Over 0.4 to 2.9 (1.5 to 10)	15,245	14,219	(48,528)
Over 2.9 to 7.3 (10 to 25)	0		
Over 7.3 to 14.7 (25 to 50)	0		
Over 14.7 to 29.3 (50 to 100)	0		
Over 29.3 to 73.3 (100 to 250)	0		
Over 73.3 to 146.5 (250 to 500)	0		
Over 146.5 to 439.5 (500 to 1500)	0		
Over 439.5 (1500)	0		

TABLE C-42. 1977 POPULATION OF CAST IRON BOILERS FIRING NATURAL GAS

Boiler classification: Cast iron

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)	
Class population	809,136	143,512	(489,806)
Distribution by heat-transfer medium			
Supercritical steam	0		
Steam (high-pressure)	0		
Steam (low-pressure)	0		
Hot water	0		
Distribution by usage			
Commercial-institutional (space heating)	647,309	114,810	(391,845)
Industrial (space heating)	161,827	28,702	(137,599)
Industrial (process heat)	0		
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	526,291	38,711	(132,121)
Over 0.1 to 0.4 (0.4 to 1.5)	218,819	50,325	(171,759)
Over 0.4 to 2.9 (1.5 to 10)	64,026	54,476	(185,926)
Over 2.9 to 7.3 (10 to 25)	0		
Over 7.3 to 14.7 (25 to 50)	0		
Over 14.7 to 29.3 (50 to 100)	0		
Over 29.3 to 73.3 (100 to 250)	0		
Over 73.3 to 146.5 (250 to 500)	0		
Over 146.5 to 439.5 (500 to 1500)	0		
Over 439.5 (1500)	0		

TABLE C-43. THE 1977 POPULATION OF COMMERCIAL WATER-TUBE BOILERS FIRING PULVERIZED COAL

Boiler classification: Water-tube, commercial

Fuel and firing mechanism: Pulverized coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	14	615 (2,100)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	0	
Over 0.4 to 2.9 (1.5 to 10)	0	
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	14	615 (2,100)
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-44. THE 1977 POPULATION OF COMMERCIAL WATER-TUBE BOILERS FIRING SPREADER-STOKER COAL

Boiler classification: Water-tube, commercial

Fuel and firing mechanism: Coal, spreader-stoker

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	351	5,130 (17,530)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	0	
Over 0.4 to 2.9 (1.5 to 10)	57	80 (280)
Over 2.9 to 7.3 (10 to 25)	53	260 (890)
Over 7.3 to 14.7 (25 to 50)	146	1,630 (5,570)
Over 14.7 to 29.3 (50 to 100)	58	1,265 (4,320)
Over 29.3 to 73.3 (100 to 250)	30	1,295 (4,420)
Over 73.3 to 146.5 (250 to 500)	7	600 (2,050)
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-45. THE 1977 POPULATION OF COMMERCIAL WATER-TUBE BOILERS FIRING UNDERFEED-STOKER COAL

Boiler classification: Water-tube, commercial

Fuel and firing mechanism: Coal, underfeed-stoker

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,724	11,030 (37,640)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	372	105 (350)
Over 0.4 to 2.9 (1.5 to 10)	510	775 (2,640)
Over 2.9 to 7.3 (10 to 25)	243	1,195 (4,070)
Over 7.3 to 14.7 (25 to 50)	423	4,690 (16,020)
Over 14.7 to 29.3 (50 to 100)	162	3,535 (12,070)
Over 29.3 to 73.3 (100 to 250)	11	450 (1,540)
Over 73.3 to 146.5 (250 to 500)	3	280 (950)
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-46. THE 1977 POPULATION OF COMMERCIAL WATER-TUBE BOILERS FIRING OVERFEED-STOKER COAL

Boiler classification: Water-tube, commercial

Fuel and firing mechanism: Coal, overfeed-stoker

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	278	2,835 (9,660)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	20	5 (20)
Over 0.4 to 2.9 (1.5 to 10)	63	100 (330)
Over 2.9 to 7.3 (10 to 25)	33	160 (560)
Over 7.3 to 14.7 (25 to 50)	113	1,240 (4,230)
Over 14.7 to 29.3 (50 to 100)	42	915 (3,110)
Over 29.3 to 73.3 (100 to 250)	5	225 (770)
Over 73.3 to 146.5 (250 to 500)	2	190 (640)
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-47. THE 1977 POPULATION OF COMMERCIAL WATER-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Water-tube, commercial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	4,081	45,280 (154,540)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	399	140 (480)
Over 0.4 to 2.9 (1.5 to 10)	772	1,160 (3,960)
Over 2.9 to 7.3 (10 to 25)	710	3,380 (11,540)
Over 7.3 to 14.7 (25 to 50)	1,406	15,000 (51,180)
Over 14.7 to 29.3 (50 to 100)	551	11,880 (40,550)
Over 29.3 to 73.3 (100 to 250)	198	8,530 (29,120)
Over 73.3 to 146.5 (250 to 500)	39	3,800 (12,970)
Over 146.5 to 439.5 (500 to 1500)	6	1,390 (4,740)
Over 439.5 (1500)	0	

TABLE C-48. THE 1977 POPULATION OF COMMERCIAL WATER-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Water-tube, commercial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	3,399	13,170 (44,940)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,552	550 (1,860)
Over 0.4 to 2.9 (1.5 to 10)	1,183	1,380 (4,720)
Over 2.9 to 7.3 (10 to 25)	204	920 (3,130)
Over 7.3 to 14.7 (25 to 50)	302	3,070 (10,490)
Over 14.7 to 29.3 (50 to 100)	107	2,415 (8,240)
Over 29.3 to 73.3 (100 to 250)	32	2,480 (8,460)
Over 73.3 to 146.5 (250 to 500)	16	1,700 (5,800)
Over 146.5 to 439.5 (500 to 1500)	3	655 (2,240)
Over 439.5 (1500)	0	

TABLE C-49. THE 1977 POPULATION OF COMMERCIAL WATER-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Water-tube, commercial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	2,952	31,225 (106,580)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	893	310 (1,070)
Over 0.4 to 2.9 (1.5 to 10)	723	985 (3,360)
Over 2.9 to 7.3 (10 to 25)	330	1,640 (5,600)
Over 7.3 to 14.7 (25 to 50)	535	5,800 (19,790)
Over 14.7 to 29.3 (50 to 100)	280	5,955 (20,320)
Over 29.3 to 73.3 (100 to 250)	143	6,260 (21,370)
Over 73.3 to 146.5 (250 to 500)	37	3,630 (12,390)
Over 146.5 to 439.5 (500 to 1500)	7	1,580 (5,400)
Over 439.5 (1500)	4	5,065 (17,280)

TABLE C-50. THE 1977 POPULATION OF COMMERCIAL SCOTCH FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (Scotch), commercial

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	5,468	4,593 (15,678)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	4,172	1,222 (4,172)
Over 0.4 to 2.9 (1.5 to 10)	1,032	1,738 (5,932)
Over 2.9 to 7.3 (10 to 25)	216	1,105 (3,772)
Over 7.3 to 14.7 (25 to 50)	48	528 (1,802)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-51. THE 1977 POPULATION OF COMMERCIAL FIREBOX FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (firebox), commercial

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	8,375	5,440 (18,569)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	6,999	2,050 (6,999)
Over 0.4 to 2.9 (1.5 to 10)	1,146	1,931 (6,591)
Over 2.9 to 7.3 (10 to 25)	182	931 (3,176)
Over 7.3 to 14.7 (25 to 50)	48	528 (1,803)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-52. THE 1977 POPULATION OF COMMERCIAL HRT FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (HRT), commercial

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	2,014	2,063 (7,043)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,346	394 (1,346)
Over 0.4 to 2.9 (1.5 to 10)	516	869 (2,966)
Over 2.9 to 7.3 (10 to 25)	148	756 (2,581)
Over 7.3 to 14.7 (25 to 50)	4	44 (150)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-53. THE 1977 POPULATION OF OTHER COMMERCIAL FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (other), commercial

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,136	682 (2,327)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	942	276 (942)
Over 0.4 to 2.9 (1.5 to 10)	172	290 (988)
Over 2.9 to 7.3 (10 to 25)	22	116 (397)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-54. THE 1977 POPULATION OF COMMERCIAL SCOTCH FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (Scotch), commercial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	7,729	9,010 (30,753)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	4,866	1,425 (4,865)
Over 0.4 to 2.9 (1.5 to 10)	2,196	3,504 (11,958)
Over 2.9 to 7.3 (10 to 25)	555	2,852 (9,734)
Over 7.3 to 14.7 (25 to 50)	112	1,229 (4,196)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-55. THE 1977 POPULATION OF COMMERCIAL FIREBOX FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (firebox), commercial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	10,589	9,482 (32,362)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	8,156	2,390 (8,156)
Over 0.4 to 2.9 (1.5 to 10)	2,110	3,393 (11,580)
Over 2.9 to 7.3 (10 to 25)	481	2,470 (8,430)
Over 7.3 to 14.7 (25 to 50)	112	1,229 (4,196)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-56. THE 1977 POPULATION OF COMMERCIAL HRT FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (HRT), commercial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	2,309	2,660 (8,871)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,522	466 (1,522)
Over 0.4 to 2.9 (1.5 to 10)	546	917 (3,128)
Over 2.9 to 7.3 (10 to 25)	241	1,237 (4,221)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-57. THE 1977 POPULATION OF OTHER COMMERCIAL FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (other), commercial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,548	1,164 (3,971)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,187	348 (1,187)
Over 0.4 to 2.9 (1.5 to 10)	310	499 (1,702)
Over 2.9 to 7.3 (10 to 25)	42	215 (732)
Over 7.3 to 14.7 (25 to 50)	9	102 (350)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-58. THE 1977 POPULATION OF COMMERCIAL SCOTCH FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (Scotch), commercial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	7,868	8,445 (28,838)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	4,949	1,447 (4,929)
Over 0.4 to 2.9 (1.5 to 10)	2,400	3,828 (13,080)
Over 2.9 to 7.3 (10 to 25)	433	2,226 (7,595)
Over 7.3 to 14.7 (25 to 50)	86	944 (3,234)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-59. THE 1977 POPULATION OF COMMERCIAL FIREBOX FIRE-TUBE BOILERS, FIRING DISTILLATE OIL

Boiler classification: Fire-tube (firebox), commercial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	11,061	9,009 (30,767)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	8,296	2,433 (8,321)
Over 0.4 to 2.9 (1.5 to 10)	2,304	3,704 (12,640)
Over 2.9 to 7.3 (10 to 25)	375	1,928 (6,572)
Over 7.3 to 14.7 (25 to 50)	86	944 (3,234)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-60. THE 1977 POPULATION OF COMMERCIAL HRT FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (HRT), commercial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	2,336	2,667 (8,487)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,457	451 (1,537)
Over 0.4 to 2.9 (1.5 to 10)	594	1,176 (3,400)
Over 2.9 to 7.3 (10 to 25)	188	961 (3,286)
Over 7.3 to 14.7 (25 to 50)	7	79 (264)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-61. THE 1977 POPULATION OF OTHER COMMERCIAL FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (other), commercial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,580	1,066 (3,617)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,209	355 (1,219)
Over 0.4 to 2.9 (1.5 to 10)	338	544 (1,840)
Over 2.9 to 7.3 (10 to 25)	33	167 (588)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-62. THE 1977 POPULATION OF COMMERCIAL SCOTCH FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (Scotch), commercial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	12,847	10,421 (35,549)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	9,561	2,801 (9,546)
Over 0.4 to 2.9 (1.5 to 10)	2,761	4,452 (15,200)
Over 2.9 to 7.3 (10 to 25)	445	2,287 (7,800)
Over 7.3 to 14.7 (25 to 50)	80	881 (3,003)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-63. THE 1977 POPULATION OF COMMERCIAL FIREBOX FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (firebox), commercial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10⁶ Btu/h)
Class population	19,226	11,981 (40,872)
Distribution by capacity ranges, thermal MW (10⁶ Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	16,031	4,695 (16,021)
Over 0.4 to 2.9 (1.5 to 10)	2,732	4,438 (15,140)
Over 2.9 to 7.3 (10 to 25)	383	1,967 (6,708)
Over 7.3 to 14.7 (25 to 50)	80	881 (3,003)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-64. THE 1977 POPULATION OF COMMERCIAL HRT FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (HRT), commercial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	4,066	3,462 (11,835)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	3,020	884 (3,034)
Over 0.4 to 2.9 (1.5 to 10)	819	1,376 (4,700)
Over 2.9 to 7.3 (10 to 25)	220	1,128 (3,848)
Over 7.3 to 14.7 (25 to 50)	7	74 (253)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-65. THE 1977 POPULATION OF OTHER COMMERCIAL FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (others), commercial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	2,717	1,511 (5,184)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	2,277	666 (2,294)
Over 0.4 to 2.9 (1.5 to 10)	403	656 (2,240)
Over 2.9 to 7.3 (10 to 25)	37	189 (650)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-66. THE 1977 POPULATION OF COMMERCIAL CAST IRON BOILERS FIRING COAL

Boiler classification: Cast iron, commercial

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	143,864	25,269 (86,242)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	90,630	4,801 (16,386)
Over 0.1 to 0.4 (0.4 to 1.5)	37,408	9,855 (33,636)
Over 0.4 to 2.9 (1.5 to 10)	15,826	10,613 (36,220)
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-67. THE 1977 POPULATION OF COMMERCIAL CAST IRON BOILERS FIRING RESIDUAL OIL

Boiler classification: Cast iron, commercial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	239,574	43,019 (146,821)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	162,855	12,022 (41,029)
Over 0.1 to 0.4 (0.4 to 1.5)	57,291	12,867 (43,914)
Over 0.4 to 2.9 (1.5 to 10)	19,428	18,130 (61,878)
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-68. THE 1977 POPULATION OF COMMERCIAL CAST IRON BOILERS FIRING DISTILLATE OIL

Boiler classification: Cast iron, commercial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	150,455	26,991 (92,119)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	102,266	7,542 (25,742)
Over 0.1 to 0.4 (0.4 to 1.5)	35,983	8,074 (27,555)
Over 0.4 to 2.9 (1.5 to 10)	12,196	11,375 (38,822)
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-69. THE 1977 POPULATION OF COMMERCIAL CAST IRON BOILERS FIRING NATURAL GAS

Boiler classification: Cast iron, commercial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	647,309	114,810 (391,845)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	421,033	30,969 (105,697)
Over 0.1 to 0.4 (0.4 to 1.5)	175,055	40,260 (137,407)
Over 0.4 to 2.9 (1.5 to 10)	51,221	43,581 (148,741)
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-70. THE 1977 POPULATION OF INDUSTRIAL WATER-TUBE BOILERS FIRING PULVERIZED COAL

Boiler classification: Water-tube, industrial

Fuel and firing mechanism: Pulverized coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	719	60,075 (205,000)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	0	
Over 0.4 to 2.9 (1.5 to 10)	0	
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	453	19,895 (67,900)
Over 73.3 to 146.5 (250 to 500)	191	18,460 (63,000)
Over 146.5 to 439.5 (500 to 1500)	64	13,980 (47,700)
Over 439.5 (1500)	11	7,740 (26,400)

TABLE C-71. THE 1977 POPULATION OF INDUSTRIAL WATER-TUBE BOILERS FIRING SPREADER-STOKER COAL

Boiler classification: Water-tube, industrial

Fuel and firing mechanism: Coal, spreader-stoker

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,357	42,200 (143,900)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	0	
Over 0.4 to 2.9 (1.5 to 10)	46	70 (220)
Over 2.9 to 7.3 (10 to 25)	89	450 (1,510)
Over 7.3 to 14.7 (25 to 50)	375	4,200 (14,330)
Over 14.7 to 29.3 (50 to 100)	285	6,175 (21,080)
Over 29.3 to 73.3 (100 to 250)	474	20,295 (69,280)
Over 73.3 to 146.5 (250 to 500)	76	6,900 (23,550)
Over 146.5 to 439.5 (500 to 1500)	9	2,260 (7,700)
Over 439.5 (1500)	3	1,850 (6,300)

TABLE C-72. THE 1977 POPULATION OF INDUSTRIAL WATER-TUBE BOILERS FIRING UNDERFEED-STOKER COAL

Boiler classification: Water-tube, industrial

Fuel and firing mechanism: Coal, underfeed-stoker

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	3,076	44,360 (151,360)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	160	45 (150)
Over 0.4 to 2.9 (1.5 to 10)	418	635 (2,160)
Over 2.9 to 7.3 (10 to 25)	414	2,035 (6,930)
Over 7.3 to 14.7 (25 to 50)	1,086	12,070 (41,180)
Over 14.7 to 29.3 (50 to 100)	788	17,265 (58,930)
Over 29.3 to 73.3 (100 to 250)	169	7,080 (24,160)
Over 73.3 to 146.5 (250 to 500)	35	3,210 (10,950)
Over 146.5 to 439.5 (500 to 1500)	5	1,110 (3,800)
Over 439.5 (1500)	1	910 (3,100)

TABLE C-73. THE 1977 POPULATION OF INDUSTRIAL WATER-TUBE BOILERS FIRING OVERFEED-STOKER COAL

Boiler classification: Water-tube, industrial

Fuel and firing mechanism: Coal, overfeed-stoker

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	724	15,075 (51,370)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	8	5 (10)
Over 0.4 to 2.9 (1.5 to 10)	51	80 (270)
Over 2.9 to 7.3 (10 to 25)	56	280 (940)
Over 7.3 to 14.7 (25 to 50)	289	3,190 (10,870)
Over 14.7 to 29.3 (50 to 100)	207	4,455 (15,190)
Over 29.3 to 73.3 (100 to 250)	85	3,555 (12,130)
Over 73.3 to 146.5 (250 to 500)	24	2,160 (7,360)
Over 146.5 to 439.5 (500 to 1500)	3	730 (2,500)
Over 439.5 (1500)	1	620 (2,100)

TABLE C-74. THE 1977 POPULATION OF INDUSTRIAL WATER-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Water-tube, industrial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	11,872	176,130 (601,160)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	774	270 (920)
Over 0.4 to 2.9 (1.5 to 10)	2,443	3,670 (12,540)
Over 2.9 to 7.3 (10 to 25)	2,021	9,630 (32,860)
Over 7.3 to 14.7 (25 to 50)	3,616	38,560 (131,620)
Over 14.7 to 29.3 (50 to 100)	1,654	35,640 (121,650)
Over 29.3 to 73.3 (100 to 250)	1,039	44,790 (152,880)
Over 73.3 to 146.5 (250 to 500)	261	25,440 (86,830)
Over 146.5 to 439.5 (500 to 1500)	56	12,500 (42,660)
Over 439.5 (1500)	8	5,630 (19,200)

TABLE C-75. THE 1977 POPULATION OF INDUSTRIAL WATER-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Water-tube, industrial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	4,609	25,590 (87,360)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,376	480 (1,640)
Over 0.4 to 2.9 (1.5 to 10)	1,775	2,080 (7,080)
Over 2.9 to 7.3 (10 to 25)	455	2,040 (6,970)
Over 7.3 to 14.7 (25 to 50)	612	6,240 (21,310)
Over 14.7 to 29.3 (50 to 100)	191	4,295 (14,660)
Over 29.3 to 73.3 (100 to 250)	170	6,370 (21,740)
Over 73.3 to 146.5 (250 to 500)	25	2,550 (8,700)
Over 146.5 to 439.5 (500 to 1500)	4	865 (2,960)
Over 439.5 (1500)	1	670 (2,300)

TABLE C-76. THE 1977 POPULATION OF INDUSTRIAL WATER-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Water-tube, industrial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	15,339	275,215 (939,320)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,521	540 (1,830)
Over 0.4 to 2.9 (1.5 to 10)	2,893	3,935 (13,440)
Over 2.9 to 7.3 (10 to 25)	2,205	10,990 (37,500)
Over 7.3 to 14.7 (25 to 50)	4,328	46,910 (160,110)
Over 14.7 to 29.3 (50 to 100)	2,515	53,585 (182,880)
Over 29.3 to 73.3 (100 to 250)	1,443	63,320 (216,130)
Over 73.3 to 146.5 (250 to 500)	302	29,360 (100,210)
Over 146.5 to 439.5 (500 to 1500)	96	21,010 (71,700)
Over 439.5 (1500)	36	45,565 (155,520)

TABLE C-77. THE 1977 POPULATION OF INDUSTRIAL SCOTCH FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (Scotch), industrial

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	3,123	5,187 (17,701)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,788	524 (1,788)
Over 0.4 to 2.9 (1.5 to 10)	844	1,422 (4,853)
Over 2.9 to 7.3 (10 to 25)	367	1,882 (6,423)
Over 7.3 to 14.7 (25 to 50)	124	1,359 (4,637)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-78. THE 1977 POPULATION OF INDUSTRIAL FIREBOX FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube, (firebox), industrial

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	4,370	5,402 (18,437)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	2,999	879 (2,999)
Over 0.4 to 2.9 (1.5 to 10)	938	1,580 (5,393)
Over 2.9 to 7.3 (10 to 25)	309	1,584 (5,409)
Over 7.3 to 14.7 (25 to 50)	124	1,359 (4,636)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-79. THE 1977 POPULATION OF INDUSTRIAL HRT FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (HRT), industrial

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,260	2,281 (7,786)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	577	169 (577)
Over 0.4 to 2.9 (1.5 to 10)	422	711 (2,427)
Over 2.9 to 7.3 (10 to 25)	251	1,288 (4,395)
Over 7.3 to 14.7 (25 to 50)	10	113 (387)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-80. THE 1977 POPULATION OF OTHER INDUSTRIAL FIRE-TUBE BOILERS FIRING COAL

Boiler classification: Fire-tube (other), industrial

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	582	553 (1,889)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	404	118 (404)
Over 0.4 to 2.9 (1.5 to 10)	140	237 (809)
Over 2.9 to 7.3 (10 to 25)	38	198 (676)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-81. THE 1977 POPULATION OF INDUSTRIAL SCOTCH FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (Scotch) industrial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	18,268	25,142 (85,805)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	9,445	2,767 (9,445)
Over 0.4 to 2.9 (1.5 to 10)	6,955	11,095 (37,867)
Over 2.9 to 7.3 (10 to 25)	1,580	8,118 (27,704)
Over 7.3 to 14.7 (25 to 50)	288	3,162 (10,789)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-82. THE 1977 POPULATION OF INDUSTRIAL FIREBOX FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (firebox), industrial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	24,171	25,574 (87,283)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	15,833	4,638 (15,831)
Over 0.4 to 2.9 (1.5 to 10)	6,682	10,745 (36,671)
Over 2.9 to 7.3 (10 to 25)	1,368	7,029 (23,992)
Over 7.3 to 14.7 (25 to 50)	288	3,162 (10,789)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-83. THE 1977 POPULATION OF INDUSTRIAL HRT FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (HRT), industrial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	5,371	7,287 (24,873)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	2,953	865 (2,953)
Over 0.4 to 2.9 (1.5 to 10)	1,731	2,902 (9,907)
Over 2.9 to 7.3 (10 to 25)	687	3,520 (12,013)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-84. THE 1977 POPULATION OF OTHER INDUSTRIAL FIRE-TUBE BOILERS FIRING RESIDUAL OIL

Boiler classification: Fire-tube (other), industrial

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	3,428	3,129 (10,678)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	2,305	676 (2,304)
Over 0.4 to 2.9 (1.5 to 10)	981	1,579 (5,391)
Over 2.9 to 7.3 (10 to 25)	118	610 (2,084)
Over 7.3 to 14.7 (25 to 50)	24	264 (899)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-85. THE 1977 POPULATION OF INDUSTRIAL SCOTCH FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (Scotch), industrial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	9,127	13,895 (47,462)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	4,389	1,283 (4,371)
Over 0.4 to 2.9 (1.5 to 10)	3,599	5,742 (19,620)
Over 2.9 to 7.3 (10 to 25)	964	4,954 (16,905)
Over 7.3 to 14.7 (25 to 50)	175	1,916 (6,566)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-86. THE 1977 POPULATION OF INDUSTRIAL FIREBOX FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (firebox), industrial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	11,823	13,921 (47,533)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	7,357	2,157 (7,379)
Over 0.4 to 2.9 (1.5 to 10)	3,455	5,556 (18,960)
Over 2.9 to 7.3 (10 to 25)	836	4,292 (14,628)
Over 7.3 to 14.7 (25 to 50)	175	1,916 (6,566)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-87. THE 1977 POPULATION OF INDUSTRIAL HRT FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (HRT), industrial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	2,695	4,013 (14,313)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,462	399 (1,363)
Over 0.4 to 2.9 (1.5 to 10)	892	1,314 (5,100)
Over 2.9 to 7.3 (10 to 25)	417	2,139 (7,314)
Over 7.3 to 14.7 (25 to 50)	14	161 (536)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-88. THE 1977 POPULATION OF OTHER INDUSTRIAL FIRE-TUBE BOILERS FIRING DISTILLATE OIL

Boiler classification: Fire-tube (other), industrial

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	1,651	1,504 (5,083)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	1,072	315 (1,081)
Over 0.4 to 2.9 (1.5 to 10)	507	816 (2,760)
Over 2.9 to 7.3 (10 to 25)	72	373 (1,212)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-89. THE 1977 POPULATION OF INDUSTRIAL SCOTCH FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (Scotch), industrial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	30,953	45,009 (153,551)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	16,280	4,769 (16,254)
Over 0.4 to 2.9 (1.5 to 10)	11,045	17,808 (60,800)
Over 2.9 to 7.3 (10 to 25)	2,979	15,303 (52,200)
Over 7.3 to 14.7 (25 to 50)	649	7,129 (24,297)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-90. THE 1977 POPULATION OF INDUSTRIAL FIREBOX FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (firebox), industrial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	41,435	46,039 (157,028)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	27,295	7,995 (27,279)
Over 0.4 to 2.9 (1.5 to 10)	10,928	17,752 (60,560)
Over 2.9 to 7.3 (10 to 25)	2,563	13,163 (44,892)
Over 7.3 to 14.7 (25 to 50)	649	7,129 (24,297)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-91. THE 1977 POPULATION OF INDUSTRIAL HRT FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (HRT), industrial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	9,946	15,158 (51,765)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	5,143	1,506 (5,166)
Over 0.4 to 2.9 (1.5 to 10)	3,278	5,504 (18,800)
Over 2.9 to 7.3 (10 to 25)	1,472	7,552 (25,752)
Over 7.3 to 14.7 (25 to 50)	53	596 (2,047)
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-92. THE 1977 POPULATION OF OTHER INDUSTRIAL FIRE-TUBE BOILERS FIRING NATURAL GAS

Boiler classification: Fire-tube (other), industrial

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	5,733	4,839 (17,216)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	0	
Over 0.1 to 0.4 (0.4 to 1.5)	3,876	1,134 (3,906)
Over 0.4 to 2.9 (1.5 to 10)	1,611	2,624 (8,960)
Over 2.9 to 7.3 (10 to 25)	246	1,261 (4,350)
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to·73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-93. THE 1977 POPULATION OF INDUSTRIAL CAST IRON BOILERS FIRING COAL

Boiler classification: Cast iron, industrial (space heating)

Fuel and firing mechanism: Coal

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	35,965	6,317 (21,560)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	22,657	1,200 (4,096)
Over 0.1 to 0.4 (0.4 to 1.5)	9,352	2,464 (8,409)
Over 0.4 to 2.9 (1.5 to 10)	3,956	2,653 (9,055)
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-94. THE 1977 POPULATION OF INDUSTRIAL CAST IRON BOILERS FIRING RESIDUAL OIL

Boiler classification: Cast iron, industrial (space heating)

Fuel and firing mechanism: Residual oil

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	59,894	10,755 (36,706)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	40,714	3,005 (10,257)
Over 0.1 to 0.4 (0.4 to 1.5)	14,323	3,217 (10,979)
Over 0.4 to 2.9 (1.5 to 10)	4,857	4,533 (15,470)
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

TABLE C-95. THE 1977 POPULATION OF INDUSTRIAL CAST IRON BOILERS FIRING DISTILLATE OIL

Boiler classification: Cast iron, industrial (space heating)

Fuel and firing mechanism: Distillate oil

	Number	Capacity, thermal MW (10^6 Btu/h)	
Class population	37,612	6,748	(23,031)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)			
0 to 0.1 (0 to 0.4)	25,567	1,886	(6,436)
Over 0.1 to 0.4 (0.4 to 1.5)	8,996	2,018	(6,889)
Over 0.4 to 2.9 (1.5 to 10)	3,049	2,844	(9,706)
Over 2.9 to 7.3 (10 to 25)	0		
Over 7.3 to 14.7 (25 to 50)	0		
Over 14.7 to 29.3 (50 to 100)	0		
Over 29.3 to 73.3 (100 to 250)	0		
Over 73.3 to 146.5 (250 to 500)	0		
Over 146.5 to 439.5 (500 to 1500)	0		
Over 439.5 (1500)	0		

TABLE C-96. THE 1977 POPULATION OF INDUSTRIAL CAST IRON BOILERS FIRING NATURAL GAS

Boiler classification: Cast iron, industrial (space heating)

Fuel and firing mechanism: Natural gas

	Number	Capacity, thermal MW (10^6 Btu/h)
Class population	161,827	28,702 (137,599)
Distribution by capacity ranges, thermal MW (10^6 Btu/h)		
0 to 0.1 (0 to 0.4)	105,258	7,742 (66,062)
Over 0.1 to 0.4 (0.4 to 1.5)	43,764	10,065 (34,352)
Over 0.4 to 2.9 (1.5 to 10)	12,805	10,895 (37,185)
Over 2.9 to 7.3 (10 to 25)	0	
Over 7.3 to 14.7 (25 to 50)	0	
Over 14.7 to 29.3 (50 to 100)	0	
Over 29.3 to 73.3 (100 to 250)	0	
Over 73.3 to 146.5 (250 to 500)	0	
Over 146.5 to 439.5 (500 to 1500)	0	
Over 439.5 (1500)	0	

APPENDIX D
BOILER FUEL CONSUMPTION

This appendix provides a description of the data sources and procedures used to develop estimates of boiler fuel consumption. The International System of Units (SI) is not used here, because the original sources were not in SI units. To make it easier to process the data, they were not converted to SI units until final figures were obtained.

Fuel consumption figures for industrial boilers were derived from five sources:

> Mineral Industry Survey: Bituminous Coal and Lignite Distribution in 1975. U.S. Bureau of Mines, Washington, D.C., April 1976. (Referred to here as MIS-Coal.)
>
> Mineral Industry Survey: Sale of Fuel Oil and Kerosene in 1975. U.S. Bureau of Mines, Washington, D.C., September 1976. (Referred to here as MIS-Oil.)
>
> Mineral Industry Survey: Natural Gas Production and Consumption. U.S. Bureau of Mines, Washington, D.C., October 1976. (Referred to here as MIS-Gas.)
>
> Fuel and Energy Data: United States by States and Census Divisions in 1974. U.S. Bureau of Mines Information Circular IC 8739, 1977. (Referred to here as IC 8739.)
>
> Major Fuel Burning Installation Data File. Federal Energy Administration, Washington, D.C., 1975. (Referred to here as MFBI data.)

Other references used less frequently are cited in the text.

In most instances, the categories used in the sources to tabulate energy consumption statistics do not match the categories used in this study, which are:

Industrial Boilers

Coal
Residual oil
Distillate oil
Gas

Commercial and Institutional Boilers

Coal
Residual oil
Distillate oil
Gas

The sections that follow describe how the data from the energy reports were used, and how the estimates of boiler fuel consumption were compiled.

INDUSTRIAL BOILERS

Coal

MIS-Coal gives the destinations for 1975 coal shipments:

Category	Coal shipments, 10^3 tons
Electric utilities	438,558
Coke and gas plants	92,497
Retail dealers	5,043
All others	53,718
Exports, plus misc. categories	51,010
Total	640,826

The miscellaneous uses include such items as coal consumed at mines.

It was assumed for the categories, which were derived from these data (i.e., industrial and commercial coal consumption), that shipments would approximate consumption. The total industrial shipments shown above for 1975 (coke and gas plants, and the item labelled "all others") totalled 157.0 x 10^6 tons (p. 48, MIS-Coal); while IC 8739 reported 1974 consumption as 148.7 x 10^6 tons. Based on this information, the assumption seems reasonable. The most recent consumption data was compiled in 1977, when IC 8739 was published.

"All others" includes the coal that is directly consumed in industrial processes other than utility boilers and coke plants. The two major components in this category are boiler fuel and direct process heat. The MFBI data for individual states divides industrial coal consumption into percentages used in electric generation, process steam, industrial space heating, and other uses (Table D-1). These percentages were applied to the "all others" category of coal consumption for each state, so that figures for the different uses could be derived. The totals were then used to derive weighted averages for type of usage. The usage percentages are:

Category	Percentage
Electric generation	25
Space heat	15
Process steam	60

The combined consumption for industrial process steam, industrial space heating, and electric generation was taken as the estimate for coal consumption in boilers:

Category	Consumption, 10^3 tons
Electric generation	9,844
Space heat	5,906
Process steam	23,624
Total boiler fuel	39,371

Residual Oil

The consumption data for residual oil were taken from MIS-Oil (Table 3, p 4). Sales of residual oil were:

Category	Consumption 10^3 bbl
Heating	155,103
Industrial (excluding refineries)	112,362
Oil company use	50,487
Electric utility co.	454,939
Railroads	583
Vessels	96,673
Military	19,068
All other	6,066
Total	895,281

TABLE D-1. DISTRIBUTION OF COAL CONSUMPTION BY USE FROM MFBI DATA

State	Consumption, 10^3 tons/yr	Electrical generation		Space heating		Process steam		Other	
		%	10^3 tons	%	10^3 tons	%	10^3 tons	%	10^3 tons
Alabama	2,163	19	411	2	42	50	1,082	29	628
Alaska	500	33	165	60	300	7	35	0	0
Arizona	112	0	0	0	0	0	0	100	112
Arkansas	34	a		a		a		a	
California	275	0	0	10	28	90	247	0	0
Colorado	680	17	116	2	14	20	136	61	414
Connecticut	24	a		a		a		a	
Delaware	22	a		a		a		a	
Dist. of Columbia	246	1	2	86	212	12	30	1	2
Florida	18	a		a		a		a	
Georgia	365	5	18	5	18	61	223	29	106
Hawaii	0	a		a		a		a	
Idaho	386	3	12	0	0	68	262	29	112
Illinois	3,494	18	629	15	524	50	1,747	17	594
Indiana	3,545	22	780	6	213	16	567	56	1,985
Iowa	1,089	4	44	4	44	48	523	44	478
Kansas	113	a		a		a		a	
Kentucky	1,328	1	13	20	266	68	903	11	146
Louisiana	0	0	0	40	0	60	0	0	0
Maine	25	a		a		a		a	

(continued)

TABLE D-1 (continued)

State	Consumption, 10^3 tons/yr	Electrical generation		Space heating		Process steam		Other	
		%	10^3 tons	%	10^3 tons	%	10^3 tons	%	10^3 tons
Maryland	294	10	29	0		30	88	60	177
Massachusetts	91	a		a		a		a	
Michigan	3,883	5	194	23	893	36	1,398	36	1,398
Minnesota	1,140	10	114	18	205	72	821	0	0
Mississippi	20	0	0	0	0	0	0	100	20
Missouri	1,502	5	75	9	135	28	421	58	871
Montana	42	a		a		a		a	
Nebraska	259	33	86	0	0	67	173	0	0
Nevada	63	35	22	30	19	15	10	20	12
New Hampshire	4	a		a		a		a	
New Jersey	38	0	0	25	10	75	28	0	
New Mexico	0	a		a		a		a	
New York	2,121	5	106	18	382	64	1,357	13	276
North Carolina	1,245	11	137	15	187	63	784	11	137
North Dakota	480	10	48	2	10	88	422	0	0
Ohio	8,355	19	1,584	9	750	37	3,084	35	2,197
Oklahoma	17	a		a		a		a	
Oregon	98	2	2	0	0	54	53	44	43
Pennsylvania	4,598	14	644	7	322	24	1,104	55	2,528
Rhode Island	1	a		a		a		a	
South Carolina	994	39	388	4	40	57	566	0	0

(continued)

TABLE D-1 (continued)

State	Consumption, 10^3 tons/yr	Electrical generation		Space heating		Process steam		Other	
		%	10^3 tons	%	10^3 tons	%	10^3 tons	%	10^3 tons
South Dakota	50	100	50	0	0	0	0	0	0
Tennessee	1,589	5	79	12	191	72	1,144	11	175
Texas	2,325	80	1,860	1	23	14	326	5	116
Utah	460	21	97	4	18	19	87	56	258
Vermont	2	a		a		a		a	
Virginia	2,362	15	354	10	236	66	1,559	9	213
Washington	390	0	0	14	55	86	335	0	0
West Virginia	3,385	30	1,016	5	169	54	1,828	11	372
Wisconsin	1,842	20	368	19	350	59	1,087	2	37
Wyoming	539	27	146	3	16	51	275	19	102
Total	52,588	18	9,589	11	5,672	44	22,705	27	14,229

[a] Not available.

The heating category comprises household and commercial use. Fuels for industrial boilers are included under the categories for industrial and oil company use. Battelle (Kim, et al., 1974) estimated the consumption in the industrial category to be 90 percent by boilers and oil company use was estimated to be 40 percent by boilers.

These estimates yield the following totals for residual oil consumption in boilers:

Industrial	112,362 x 0.90 =	101,125 x 10^3 bbl
Oil company use	50,487 x 0.40 =	20,194 x 10^3 bbl
Total		121,319 x 10^3 bbl

MFBI data were used to derive percentages of residual oil usage comparable to those derived for coal:

Category	Percentage
Electric generation	10
Space heat	11
Process steam	56
Other	23

When applied to the total consumption of 162,849 bbl, this distribution yields the following boiler consumption:

Category	Consumption, 10^3 bbl
Electric generation	16,285
Space heat	17,914
Process steam	91,195
Total boiler fuel	124,394

Values for individual states are shown in Table D-2.

Distillate Oil

The consumption data for distillate oil were taken from MIS-Oil (Table 2, p.4). Values given by category are listed below:

TABLE D-2. DISTRIBUTION OF RESIDUAL OIL CONSUMPTION BY USE FROM MFBI DATA

State	Consumption, 10^3 bbl	Electrical generation		Space heating		Process steam		Other	
		%	10^3 bbl	%	10^3 bbl	%	10^3 bbl	%	10^3 bbl
Alabama	2,575	9	232	2	52	68	1,751	21	540
Alaska	574	4	23	0	0	96	551	0	0
Arizona	140	100	140	0	0	0	0	0	0
Arkansas	2,968	17	505	2	59	74	2,196	7	208
California	3,786	0	0	0	0	26	984	74	2,802
Colorado	973	5	49	20	195	55	534	20	195
Connecticut	5,151	11	567	14	721	50	2,576	25	1,287
Delaware	1,678	18	302	6	101	76	1,275	0	0
Dist. of Columbia	0	0	0	88	0	12	0	0	0
Florida	6,616	11	728	2	132	65	4,300	22	1,456
Georgia	4,330	12	520	1	43	75	3,247	12	520
Hawaii	187	0	0	0	0	68	127	32	60
Idaho	109	a		a		a		a	
Illinois	3,428	2	69	3	103	58	1,988	37	1,268
Indiana	4,041	9	364	13	525	53	2,142	25	1,010
Iowa	76	0	0	8	6	92	70	0	0
Kansas	214	0	0	2	4	48	103	50	107
Kentucky	220	0	0	2	4	52	114	46	102
Louisiana	3,533	6	212	2	71	54	1,920	38	1,330
Maine	4,067	19	773	6	244	69	2,806	6	244

(continued)

TABLE D-2 (continued)

State	Consumption, 10^3 bbl	Electrical generation		Space heating		Process steam		Other	
		%	10^3 bbl	%	10^3 bbl	%	10^3 bbl	%	10^3 bbl
Maryland	2,526	4	101	40	1,010	36	909	20	506
Massachusetts	5,319	11	585	30	1,596	50	2,660	9	478
Michigan	1,373	3	41	24	330	46	632	27	370
Minnesota	1,829	2	37	27	494	50	915	21	383
Mississippi	1,155	45	520	1	12	49	566	5	57
Missouri	396	a		a		a		a	
Montana	543	0	0	0	0	4	22	96	521
Nebraska	34	0	0	0	0	0	0	100	34
Nevada	12	9	1	7	1	4	0	80	10
New Hampshire	1,406	16	225	18	253	59	830	7	98
New Jersey	6,013	11	661	14	842	71	4,269	4	241
New Mexico	587	97	569	0	0	3	18	0	0
New York	5,034	5	252	17	856	33	1,661	45	2,265
North Carolina	5,445	19	1,035	6	327	64	3,485	11	598
North Dakota	9	14	1	3	0	66	6	17	2
Ohio	3,499	1	35	11	385	38	1,330	50	1,749
Oklahoma	331	1	3	1	3	81	268	17	57
Oregon	1,530	0	0	6	92	94	1,438	0	0
Pennsylvania	7,305	2	146	14	1,203	40	2,922	44	3,214
Rhode Island	937	23	216	9	84	68	637	0	0
South Carolina	2,345	11	258	3	70	63	1,477	23	540

(continued)

TABLE D-2 (continued)

State	Consumption, 10^3 bbl	Electrical generation		Space heating		Process steam		Other	
		%	10^3 bbl	%	10^3 bbl	%	10^3 bbl	%	10^3 bbl
South Dakota	51	a		a		a		a	
Tennessee	237	0	0	0	0	100	237	0	0
Texas	5,704	4	228	1	57	92	5,248	3	171
Utah	2,737	0	0	0	0	10	274	90	2,463
Vermont	195	a		a		a		a	
Virginia	6,501	13	845	25	1,625	58	3,771	4	260
Washington	2,968	28	831	19	564	48	1,425	5	148
West Virginia	834	1	8	2	17	40	334	57	475
Wisconsin	410	15	62	5	21	80	327	0	0
Wyoming	431	49	211	0	0	6	26	45	194
Total	111,611	10	11,355	11	11,922	56	62,371	23	25,963

[a] Not available.

Category	Consumption, 10^3 bbl
Heating	487,120
Industrial (excluding oil company use)	63,993
Oil company use	13,633
Electric utility Co.	65,203
Railroads	93,191
Vessels	26,138
Military	18,004
On-highway diesel	217,206
Off-highway diesel	48,977
All other	10,096
Total	1,043,561

As with residual oil, the industrial boiler consumption is included in the categories for industrial and oil company use. The MFBI data were again used to derive weighted averages for type of usage.

Category	Percent
Electric generation	8
Space heat	19
Process steam	32
Other	41

The data for individual states are shown in Table D-3.

The percentages were then applied as follows:

Category	Consumption, 10^3 bbl
Industrial	63,993
Oil company use	13,633
Total	77,626

Category	Percent	Consumption, 10^3 bbl
Electric generation	13.6	6,210
Space heat	32.2	14,749
Process steam	54.2	24,840
Total boiler fuel	100.0	45,799

It was assumed that the consumption of kerosene in boilers was negligible (See MIS-Oil, 1, p. 4). Data shown for kerosene use in 1975 are:

TABLE D-3. DISTRIBUTION OF DISTILLATE OIL CONSUMPTION BY USE FROM MFBI DATA

State	Consumption, 10^3 bbl	Electrical generation		Space heating		Process steam		Other	
		%	10^3 bbl	%	10^3 bbl	%	10^3 bbl	%	10^3 bbl
Alabama	1,285	a		a		a		a	
Alaska	305	a		a		a		a	
Arizona	2,694	45	1,212	0	0	0	0	55	1,482
Arkansas	628	a		a		a		a	
California	4,174	a		a		a		a	
Colorado	482	0	0	23	111	19	92	58	279
Connecticut	702	0	0	0	0	0	0	100	702
Delaware	377	a		a		a		a	
Dist. of Columbia	13	10	1	70	10	2	0	18	2
Florida	1,220	0	0	0	0	35	427	65	793
Georgia	1,401	0	0	8	112	25	350	67	939
Hawaii	145	a		a		a		a	
Idaho	789	a		a		a		a	
Illinois	2,211	2	44	62	1,371	16	354	20	442
Indiana	2,023	12	243	18	364	23	465	47	951
Iowa	708	0	0	5	35	95	673	0	0
Kansas	168	a		a		a		a	
Kentucky	1,181	0	0	25	295	75	886	0	0
Louisiana	1,984	a		a		a		a	
Maine	303	a		a		a		a	

(continued)

TABLE D-3 (continued)

State	Consumption, 10^3 bbl	Electrical generation		Space heating		Process steam		Other	
		%	10^3 bbl	%	10^3 bbl	%	10^3 bbl	%	10^3 bbl
Maryland	1,309	88	1,152	2	27	5	65	5	65
Massachusetts	823	0	0	0	0	0	0	100	823
Michigan	2,017	2	40	44	887	40	807	14	283
Minnesota	725	a		a		a		a	
Mississippi	540	a		a		a		a	
Missouri	1,059	24	254	2	21	74	784	0	0
Montana	1,236	a		a		a		a	
Nebraska	240	a		a		a		a	
Nevada	281	0	0	33	93	67	188	0	0
New Hampshire	94	0	0	0	0	0	0	100	94
New Jersey	2,329	0	0	41	955	0	0	59	1,374
New Mexico	798	0	0	0	0	0	0	100	798
New York	2,078	2	42	10	208	18	374	70	1,454
North Carolina	2,301	0	0	0	0	0	0	100	2,301
North Dakota	87	a		a		a		a	
Ohio	5,362	7	375	16	858	42	2,252	35	1,877
Oklahoma	1,117	0	0	0	0	100	1,117	0	0
Oregon	1,640	0	0	0	0	0	0	100	1,640
Pennsylvania	4,331	4	173	54	2,339	33	1,429	9	390
Rhoda Island	191	a		a		a		a	
South Carolina	872	a		a		a		a	

(continued)

TABLE D-3 (continued)

State	Consumption, 10^3 bbl	Electrical generation		Space heating		Process steam		Other	
		%	10^3 bbl	%	10^3 bbl	%	10^3 bbl	%	10^3 bbl
South Dakota	63	a		a		a		a	
Tennessee	1,433	0	0	22	315	65	931	13	187
Texas	2,832	32	906	0	0	68	1,926	0	0
Utah	1,426	0	0	0	0	100	1,426	0	0
Vermont	79	0	0	0	0	0	0	100	79
Virginia	2,273	11	250	3	68	86	1,955	0	0
Washington	1,803	0	0	16	288	4	72	80	1,433
West Virginia	704	0	0	0	0	0	0	100	704
Wisconsin	477	0	0	38	181	27	129	35	167
Wyoming	680	79	537	0	0	0	0	21	143
Total[b]	44,206	8	3,767	19	8,435	32	14,074	41	17,930

[a] Not available.

[b] Excluding Arizona, Iowa, and Virginia due to erroneous data.

Category	Consumption, 10^3 bbl
Heating	45,127
All other uses	12,864
Total	57,991

Gas

The industrial gas consumption was obtained from MIS-Gas (Table 7). The total for industrial gas is shown as 6,979,963 x 10^6 ft^3; this figure includes 945,557 x 10^6 ft^3 used as refinery fuel, 26,246 x 10^6 ft^3 used for carbon black production, and an unspecified amount used as chemical feedstocks. The chemical feedstock consumption was estimated by using data from a Shell Oil Company Report (Shell, 1978). In this report the consumption of natural gas for use as feedstocks is shown as 705 x 10^{12} Btu/yr or an equivalent 688,480 x 10^6 ft^3.

The MFBI data given below, are assumed to include the refinery and carbon black consumption, and the percentage distributions derived for boiler fuels and other consumption were applied to the total industrial gas consumption minus the estimated feedstock consumption.

The percentages of industrial gas consumption derived from MFBI data were:

Category	Percentage
Electric generation	7
Process steam	49
Space heat	7
Other	37
Total	100

The data from individual states are shown in Table D-4. The total consumption for boiler fuels was calculated to be:

Category	10^6 ft^3
Electric generation	440,404
Process steam	3,082,827
Space heat	440,404
Total boiler fuel	3,963,635

TABLE D-4. DISTRIBUTION OF NATURAL GAS CONSUMPTION BY USE FROM MFBI DATA.

State	Consumption, 10^6 ft^3	Electrical generation		Space heating		Process steam		Other	
		%	10^6 ft^3	%	10^6 ft^3	%	10^6 ft^3	%	10^6 ft^3
Alabama	153,540	2	3,071	1	1,535	50	76,770	47	72,164
Alaska	22,388	10	2,239	21	4,071	28	6,269	41	9,179
Arizona	50,868	39	19,839	0	0	9	4,578	52	26,451
Arkansas	128,151	5	6,407	1	1,282	63	80,735	31	39,727
California	581,609	2	11,632	1	5,816	45	261,724	52	302,437
Colorado	65,609	15	9,841	14	9,185	34	22,307	37	24,276
Connecticut	15,553	5	778	34	5,288	45	6,999	16	2,488
Delaware	6,957	0	0	1	70	37	2,574	62	4,313
Dist. of Columbia	Included with Maryland								
Florida	83,364	13	10,837	4	3,335	41	34,179	42	35,013
Georgia	145,479	7	10,184	11	16,003	56	81,468	26	37,824
Hawaii	0	a	0	a	0	a	0	a	0
Idaho	29,898	5	1,495	1	299	94	28,104	0	0
Illinois	352,291	5	17,615	7	24,660	40	140,916	48	169,100
Indiana	223,383	1	2,234	5	11,169	23	51,378	71	158,602
Iowa	121,489	13	15,794	7	8,504	48	58,315	32	38,876
Kansas	124,378	7	8,706	4	4,975	57	70,895	32	39,802
Kentucky	64,856	1	649	22	14,268	71	46,048	6	3,891
Louisiana	922,673	17	156,854	2	18,453	60	553,604	21	193,762
Maine, N. Hampshire	3,330	0	0	100	3,330	0	0	0	0
Maryland, D.C.	43,165	36	15,539	6	2,590	52	22,446	6	2,590

(continued)

TABLE D-4 (continued)

State	Consumption, 10^6 ft^3	Electrical generation		Space heating		Process steam		Other	
		%	10^6 ft^3	%	10^6 ft^3	%	10^6 ft^3	%	10^6 ft^3
Massachusetts	23,986	4	959	7	1,679	88	21,108	1	240
Michigan	301,573	12	36,189	28	84,440	29	87,456	31	93,488
Minnesota	100,539	7	7,038	19	19,102	46	46,248	28	28,151
Mississippi	98,848	3	2,965	1	988	58	57,332	38	37,563
Missouri	89,913	5	4,496	15	13,487	56	50,351	24	21,579
Montana	31,631	13	4,112	9	2,847	39	12,336	39	12,336
Nebraska	72,792	0	0	6	4,368	41	29,845	53	38,579
Nevada	10,043	0	0	0	0	0	0	100	10,043
New Hampshire	Included with Maine								
New Jersey	52,361	17	8,901	13	6,807	46	24,086	24	12,567
New Mexico	57,773	36	20,798	27	15,599	8	4,622	29	16,754
New York	104,429	5	5,221	20	20,886	19	19,842	56	58,480
North Carolina	62,094	9	5,588	36	22,354	47	29,184	8	4,968
North Dakota	1,975	a		a		a		a	
Ohio	341,612	8	27,329	6	20,497	29	99,067	57	194,719
Oklahoma	142,813	2	2,856	4	5,713	56	79,975	38	54,269
Oregon	57,332	0	0	3	1,720	73	41,852	24	13,760
Pennsylvania	261,447	4	10,458	5	13,072	30	78,434	61	159,483
Rhode Island	5,820	a		a		a		a	
South Carolina	70,329	3	2,110	10	7,033	51	35,868	36	25,318

(continued)

TABLE D-4 (continued)

State	Consumption, 10^6 ft^3	Electrical generation		Space heating		Process steam		Other	
		%	10^6 ft^3	%	10^6 ft^3	%	10^6 ft^3	%	10^6 ft^3
South Dakota	5,813	0	0	5	291	70	4,069	25	1,453
Tennessee	111,281	9	10,015	5	5,564	64	71,220	22	24,482
Texas	1,396,790	3	41,904	1	13,698	63	879,978	33	460,941
Utah	48,104	59	28,381	0	0	1	481	40	19,242
Vermont	Included with Maine								
Virginia	36,427	2	729	15	5,464	75	27,320	8	2,914
Washington	92,142	2	1,843	15	13,821	52	47,914	31	28,564
West Virginia	66,155	2	1,323	8	5,292	54	35,724	36	23,816
Wisconsin	152,443	7	10,671	36	54,879	42	64,026	15	22,867
Wyoming	43,618	4	1,745	1	436	72	31,405	23	10,032
Totals[b]	6,846,885	7	506,266	7	475,035	49	3,364,965	37	2,500,619

[a] Not available.

[b] Excluding Arizona, Idaho, Rhode Island, and Wyoming due to erroneous data.

COMMERCIAL BOILERS

Coal

The figures for commercial coal consumption were obtained from MIS-Coal (p. 48). The basic data have been discussed earlier in the section for industrial coal. The categories involved are:

Coal shipments, 10^3 tons

Category	
Electric utilities	438,558
Coke and gas plants	92,497
Retail dealers	5,043
All others	53,718
Exports, plus misc. categories (totaling 2.3×10^3 tons)	51,010
Total	640,826

Consumption in residential boilers was considered negligible. Shipments to retail dealers were assumed to be used in commercial boilers. For 1974, IC 8739 shows coal consumption in the household-commercial category at 6558×10^3 tons (p. 22). This figure is similar to the reported 1975 coal shipments to retail dealers of 6792×10^3 tons (MIS-Coal, p. 48). Hence, the categories are comparable.

Residual Oil

The data for commercial boiler consumption were derived from MIS-Oil (Table 3, p. 4). In this source, the category labelled "Heating" in the discussion of industrial residual oil consumption was assumed to refer to commercial boilers. The 1975 sales for residual oil in this category totaled $172,892 \times 10^3$ bbl. The 1974 consumption figures from IC 8739 (p. 134) show $167,415 \times 10^3$ bbl in the household-commercial category. According to Battelle, fuel in this category would be burned in large apartment and commercial buildings, using boilers of the type classified as commercial for this study. Consequently, the $155,103 \times 10^3$ bbl of residual oil given in MIS-Oil (Table 3, p. 4) were classified as commercial boiler fuel.

Distillate Oil

The data for "Heating" shown in MIS-Oil (Table 2, p. 4) were used to derive the amounts of distillate oil consumed in commercial boilers. A considerable portion of the distillate oil in this category was known to be burned in residences. Because residential consumption is not reported separately, an indirect approach was taken to determine the portion. The number of residential burners in service as of January 1, 1976, was reported to be 12,020,936 (Fuel Oil and Oil Heat, 1978). The Battelle boiler inventory report (Putman et al., 1975) estimated the average residential burner to be a unit consuming 153×10^6 Btu/yr. This figure was apparently an error in computation, if other Battelle data (Tables 10 and 11, p. 24) are correct. The number of oil-burning residential units is given as $14{,}800 \times 10^3$ units, and the consumption of oil and kerosene in residential units as $2{,}424 \times 10^{12}$ Btu. The calculated average residential consumption is:

$$\text{Avg. consumption per unit} = \frac{2424 \times 10^{12} \text{ Btu}}{14.8 \times 10^6 \text{ Btu}} = 164 \times 10^6 \text{ Btu}$$

Using this figure and the total number of residential burners in service, the total residential consumption is calculated as:

$$\begin{aligned}\text{Residential consumption, 1975} &= 12{,}020{,}936 \times 164 \times 10^6 \text{ Btu} \\ &= 1977.3 \times 10^{12} \text{ Btu}\end{aligned}$$

The total heating value of oil in MIS-Oil under the heating category is:

$$\begin{aligned}\text{Heating category} &= 487{,}120 \times 10^3 \text{ bbl} \times 5.83 \times 10^6 \frac{\text{Btu}}{\text{bbl}} \\ &= 2839.9 \times 10^{12} \text{ Btu}\end{aligned}$$

Subtracting the residential consumption from the total, the commercial consumption is calculated as:

All heating	2839.9×10^{12} Btu
Residential consumption	1977.3×10^{12} Btu
Commercial consumption	862.6×10^{12} Btu

$$\text{Commercial consumption} = \frac{862.2 \times 10^{12}}{5.83 \times 10^6} = 147{,}959 \times 10^3 \text{ bbl}$$

Gas

Data for gas burned in commercial boilers were derived from MIS-Gas (Table 7). The total amount of gas delivered to commercial customers was 2,268,128 x 10^6 ft^3. According to Stanford (1972), 66 percent of the gas sent to commercial customers is used for space heating, with the balance of 34 percent being used for water heating, air conditioning, and cooking.

Total for commercial boilers = 0.66 (2,268,126) x 10^6 ft^3
= 1,496,963 x 10^6 ft^3

FUEL CONSUMPTION SUMMARY

Factors for converting the figures for fuel consumed to Btu's were taken from IC 8739 and are shown below:

p 7, Natural gas	1024 Btu/ft^3
p 7, Distillate oil	5.83 x 10^6 Btu/bbl
p 7, Residual oil	6.29 x 10^6 Btu/bbl
p 22, Coal	24.8 x 10^6 Btu/ton

The coal value was calculated from the total industrial coal shipments for 1974 (148,772 x 10^3 tons) and the reported Btu equivalent (3689.2 x 10^{12} Btu).

Final consumption figures are summarized below:

Industrial	Quantity	Btu's, 10^{12}
Coal (10^3 tons)	39,374	976.5
Residual oil (10^3 bbl)	125,067	786.7
Distillate oil (10^3 bbl)	45,799	267.0
Gas (10^6 ft^3)	3,963,635	4,058.8
Commercial		
Coal (10^3 tons)	5,043	125.1
Residual oil (10^3 bbl)	155,103	975.6
Distillate oil (10^3 bbl)	147,959	862.6
Gas (10^6 ft^3)	2,268,128	2322.4

REFERENCES FOR APPENDIX D

Fejer, M.E., and Larson, D.H., 1974. Study of Industrial Uses of Energy Relative to Environmental Effects. Institute for Gas Technology.

Fuel Oil and Oil Heat, 1978. Special Report. Industry Publications, Inc.

Kim, B.C., K. Murthy, and D.M. Jenkins, 1974. Pollutants from Residual Oil Combustion. Battelle Columbus Laboratories. EPA Contract No. 68-02-1323, Task 4.

Putnam, A.A., E.L. Kropp, and R.E. Barrett, 1975. Evaluation of National Boiler Inventory. Battelle Columbus Laboratories. EPA Contract No. 68-02-1223, Task 31.

Shell Oil Company, 1978. National Energy Outlook, 1980 to 1990.

Stanford Research Institute, 1972. Patterns of Energy Consumption in the United States. PB-212776.

APPENDIX E

DERIVATION OF THE PEDCO INDUSTRIAL BOILER GROWTH FACTOR

This appendix provides a description of the data sources and procedures used to develop estimates of boiler growth. The International System of Units (SI) is not used here, because the original sources were not in SI units. To make it easier to process the data, they were not converted to SI units until final figures were obtained.

The main reference used for the development of the PEDCo industrial boiler growth factor was: Study of Industrial Uses of Energy Relative to Environmental Effects, written by the Institute of Gas Technology (IGT) for the U.S. Environmental Protection Agency in July 1974. From this report, energy uses for the four most energy-intensive industries were calculated for the years 1971, 1975, 1980, and 1985. The report provides the IGT estimates of future industrial production. By assuming a constant ratio of energy consumed to tons of product produced, the energy for other years was calculated. For example (IGT, p. II-1), the total energy use for the paper and paperboard industries in 1971 was 1310 x 10^{12} Btu. The production for 1971 was 56 x 10^6 tons. The IGT report estimates that the 1980 production of this industry will be 77 x 10^6 tons. The ratio of energy use to tons of product was held constant at 23.39 x 10^6 Btu/ton. Thus, in 1980, to produce 77 x 10^6 tons would require 1802 x 10^{12} Btu. The energy use for the four key industries in 1971, 1975, 1980, and 1985 are presented in Table E-1.

Two calculations were then conducted to determine:

- The percentage that each Standard Industrial Classification (SIC) represented of the total energy use for each year.
- The percentage rate of growth for the total time interval (i.e., 1971-1985) for each SIC.

TABLE E-1. PROJECTED TOTAL ENERGY USAGE BY THE FOUR MAJOR ENERGY-INTENSIVE INDUSTRIES
[10^{15} J (10^{12} Btu)]

Industry	1971	1975	1980	1985
Paper and allied products	1,284 (1,218)	1,537 (1,459)	1,766 (1,675)	2,018 (1,914)
Chemical products	3,969 (3,764)	4,824 (4,575)	587 (5,569)	6,936 (6,484)
Mineral products	724 (687)	802 (761)	879 (834)	948 (899)
Primary metals	4,074 (3,864)	4,884 (4,632)	5,894 (5,590)	6,921 (6,564)
Total	10,051 (9,533)	12,047 (11,426)	14,411 (13,668)	16,723 (15,861)

The purpose of these calculations was to determine an overall growth factor for the four industries during the 1971 to 1985 period.

The percentage of the total energy use for each indicated year is shown in Table E-2.

TABLE E-2. PERCENTAGE OF TOTAL ENERGY USE BY INDUSTRIAL CLASSIFICATION

Standard Industrial Classification	1971	1975	1980	1985	Avg., %
26	12.8	12.8	12.3	12.1	12.5
28	39.5	40.0	40.7	40.9	40.3
32	7.2	6.7	6.1	5.6	6.4
33	40.5	40.5	40.9	41.4	40.8
Total	100	100	100	100	100

The rate of growth for the 14-year period was derived by the following expression:

$$\sqrt[14]{\frac{\text{1985 energy use}}{\text{1971 energy use}}}$$

For example, for SIC 26,

$$\text{Rate of growth} = \sqrt[14]{\frac{1914}{1218}} = 1.033$$

These rates of growth were then utilized with the percentage of the total energy use by each SIC to derive a weighted average rate of growth industry-wide. This calculation is presented as:

$$\underset{\text{SIC 26}}{(0.125 \times 1.033)} + \underset{\text{SIC 28}}{(0.403 \times 1.04)} + \underset{\text{SIC 32}}{(0.064 \times 1.02)} + \underset{\text{SIC 33}}{(0.408 \times 1.039)}$$

= 1.037.

The growth factor was assumed to be representative for all industry and applicable through the year 2000. Thus, a formula for calculating use for any given year was derived.

The equation for calculating energy use for the four key industries for this period can be expressed as:

$$E_f = (E_p)(1.037^x)$$

where

E_f = Energy use at some future date

E_p = Energy use in 1985

x = The number of years between 1985 and the future date.

APPENDIX F

ESTIMATION OF BOILER AIR EMISSIONS

GENERAL

The reports from which emissions were derived are as follows:

Annual Summary of Cost and Quality of Steam - Electric Plant Fuels - 1975. Federal Power Commission, May 1976. (Referred to here as FPC.)

Mineral Industry Survey. Bituminous Coal and Lignite Distributions - 1975. U.S. Bureau of Mines, Washington, D.C. April 1976. (Referred to here as MIS - Coal.)

Major Fuel Burning Installation Data File. Federal Energy Administration, Washington, D.C. 1975. (Referred to here as MFBI.)

AP-42 Emission Factors, Section 1. External Combustion Sources. U.S. Environmental Protection Agency. (Referred to here as AP-42.)

Heating Oils - 1977. Battesville Energy Research Center. Energy Research and Development Administration. August 1977. (Referred to here as Heating Oils.)

Design Trends and Operating Problems in Combustion Modification of Industrial Boilers. Battelle Columbus Laboratories. March 1974. (Referred to here as Battelle design study.)

Mineral Industry Survey. Sale of Fuel Oil and Kerosene in 1975. U.S. Bureau of Mines, Washington, D.C. September 1976. (Referred to here as MIS - Oil.)

The basic steps in deriving estimates of boiler emissions are described below:

1) Average percentages of sulfur and ash were derived from data on quality of coal, residual oil, and distillate oil being used.

2) Emission factors from AP-42 were reviewed to find those that corresponded to particular boiler types. On this basis, the present boiler population was divided into the following nine categories:

   a) Pulverized coal
   b) Spreader stoker
   c) Overfeed stoker
   d) Underfeed stoker
   e) Other stoker
   f) Residual oil
   g) Distillate oil
   h) Natural gas (industrial)
   i) Natural gas (commercial)

3) The boiler capacity data were analyzed to determine the percentage of total capacity in each of the above categories.

4) Fuel consumption, which was assumed to be proportional to total capacity, was calculated for each boiler category by using the percentages derived in Step 3.

5) Estimates were compiled for uncontrolled discharges of sulfur dioxide, particulate matter, nitrogen oxides, hydrocarbons, and carbon monoxide, based on the level of fuel consumption and the sulfur and ash content.

These computations are discussed below.

DETERMINATION OF SULFUR AND ASH PERCENTAGES

State coal consumption in the "all others" category (MIS-Coal, 1975, pp. 49-50) was multiplied by the fraction of coal that is consumed as boiler fuel (MFBI, 1975) to find the amount for coal burned in boilers. This amount was used with the weighted average percentage of sulfur in coals burned in utility boilers to find the amount of sulfur in the coal. The percentage of sulfur was taken from data from the Federal Power Commission (FPC, 1976, pp. 4-5) and the values reported for utility boilers were assumed to apply to all boilers in the individual states. The total sulfur in the coals burned in each state was calculated. Based on this total and on the total boiler fuel burned in industrial boilers, a weighted average sulfur content was derived for the coal burned in individual states.

Sample calculations are shown below:

Alabama

Consumption of "all others" coal, from MIS-Coal (p. 50)	2163×10^3 tons
Percentage of boiler coal, from MFBI (1975)	71 percent
Percentage of sulfur in coal, from FPC	2.3 percent
Sulfur content of boiler coal $= 2163 \times 10^3 (0.71)(0.023) =$	35,000 tons

The tons of sulfur per ton of coal and the total coal consumption were summed for individual states. From this, a weighted average percentage of sulfur in boiler coals was calculated.

The "all other" consumption data, the MFBI percentage for industrial boilers, the percentage of sulfur in the coal, and the derived values for sulfur content are shown in Table F-1. The weighted national average for sulfur was 2.0 percent.

The same approach was used to find the weighted national average for ash, which is 13.4 percent. The data for this computation are shown in Table F-2.

A similar approach was used to find the national average percentages of sulfur in residual and distillate oil. For oil, individual state sulfur levels were taken from Heating Oils (1977, p. 13, Table 6). Regional values were used for all states included in the regions shown in Figure 1 of that publication for states that were included in more than one region, and an average value was used. Data on oil consumption, by state, were taken from MIS-Oil. The results showed average sulfur levels for residual and distillate oils at 1.51 and 0.235 percent, respectively. Data for the computations are shown in Tables F-3 and F-4.

AP-42 EMISSION FACTORS

The emission factors from AP-42 pertaining to industrial boilers were given as:

TABLE F-1. SULFUR CONTENT OF COAL

State	Total coal consumption, 10^3 tons	Consumption by boilers, %	Sulfur content, %	Sulfur content, tons
Alabama	2,163	71	2.3	35,300
Arizona	112	N.A.	0.5	-0-
Arkansas	34	73	0.6	149
California	275	73	0.5	1,003
Colorado	680	39	0.5	1,326
Connecticut	24	73	1.9	333
Delaware	22	73	2.1	337
Florida	18	71	2.9	371
Georgia	365	73	1.8	4,796
Idaho	386	73	0.5	1,409
Illinois	3,494	83	2.4	69,600
Indiana	3,545	44	2.8	43,674
Iowa	1,089	56	2.0	12,197
Kansas	113	73	3.2	2,640
Kentucky	1,328	89	3.3	39,003
Louisiana	-0-	100	0.6	-0-
Maine	25	73	1.9	347
Maryland	294	40	1.6	1,882
Massachusetts	91	73	1.0	664
Michigan	3,883	64	2.4	59,643
Minnesota	1,140	100	1.3	14,820
Mississippi	20	N.A.	2.6	-0-
Missouri	1,502	42	3.3	20,818
Montana	42	73	0.7	215
Nebraska	259	100	0.9	2,331
Nevada	63	80	0.4	202
New Hampshire	4	73	2.4	70
New Jersey	38	100	1.9	722
New Mexico	-0-	73	0.6	-0-

(continued)

TABLE F-1 (continued)

State	Total coal consumption, 10^3 tons	Consumption by boilers, %	Sulfur content, %	Sulfur content, tons
New York	2,121	87	1.9	35,060
North Carolina	1,245	89	1.1	12,189
North Dakota	480	100	0.6	2,880
Ohio	8,335	65	3.0	162,532
Oklahoma	17	73	0.6	74
Oregon	98	56	0.5	274
Pennsylvania	4,598	45	2.1	43,451
Rhode Island	1	73	1.9	14
South Carolina	994	100	1.3	12,922
South Dakota	50	100	0.8	400
Tennessee	1,589	89	2.9	41,012
Texas	2,325	95	0.6	13,253
Utah	460	44	0.5	1,012
Vermont	2	73	1.0	15
Virginia	2,362	91	0.8	17,195
Washington	390	100	0.5	1,950
West Virginia	3,385	89	2.1	63,266
Wisconsin	1,842	98	2.3	41,519
Wyoming	539	81	0.5	2,183
Alaska	500	100	0.5	2,500
Hawaii	246	73	0.7	1,257
Total	52,588		2.0 (avg.)	768,810

TABLE F-2. ASH CONTENT OF COAL

State	Total coal consumption, 10^3 tons	Consumption by boilers, %	Ash content, %	Ash content, tons
Alabama	2,163	71	14.2	218
Arizona	112	N.A.	9.9	0
Arkansas	34	73	11.9	3
California	275	73	15.0	30
Colorado	680	39	8.8	23
Connecticut	24	73	9.2	2
Delaware	22	73	12.9	2
Florida	18	71	10.9	1
Georgia	365	73	11.6	31
Idaho	386	73	12.6	36
Illinois	3,494	83	10.2	296
Indiana	3,545	44	11.6	181
Iowa	1,089	56	10.2	62
Kansas	113	73	18.9	16
Kentucky	1,328	89	15.6	184
Louisiana	0	100	11.9	0
Maine	25	73	9.2	2
Maryland	294	40	13.1	15
Massachusetts	91	73	13.2	9
Michigan	3,883	64	11.9	296
Minnesota	1,140	100	9.6	109
Mississippi	20	N.A.	10.1	0
Missouri	1,502	42	13.3	84
Montana	42	73	8.7	3
Nebraska	259	100	9.4	24
Nevada	63	80	10.3	5
New Hampshire	4	73	8.0	1
New Jersey	38	100	10.9	4

N.A. - Not applicable.

(continued)

TABLE F-2 (continued)

State	Total coal consumption, 10^3 tons	Consumption by boilers, %	Ash content, %	Ash content, tons
New Mexico	0	73	22.3	0
New York	2,121	87	13.7	253
North Carolina	1,245	89	13.8	153
North Dakota	480	100	10.3	49
Ohio	8,335	65	16.1	872
Oklahoma	17	73	11.9	1
Oregon	98	56	15.0	8
Pennsylvania	4,598	45	16.1	333
Rhode Island	1	73	9.2	0
South Carolina	994	100	11.7	116
South Dakota	50	100	7.4	4
Tennessee	1,589	89	15.9	225
Texas	2,325	95	11.9	263
Utah	460	44	10.8	22
Vermont	2	73	8.6	0
Virginia	2,362	91	14.4	310
Washington	390	100	15.0	59
West Virginia	3,385	89	16.0	482
Wisconsin	1,842	98	10.6	191
Wyoming	539	81	10.4	45
Alaska	500	100	15.0	75
Hawaii	246	73	15.0	27
Total	52,588		13.4 (avg.)	5,125

TABLE F-3. SULFUR CONTENT OF RESIDUAL OIL

State	Total residual oil consumption, 10^3 bbl	Consumption by boilers, %	Sulfur content, %	Sulfur content, tons
Alabama	2,575	79	1.95	13,245
Arizona	140	100	1.32	617
Arkansas	2,968	93	1.72	15,852
California	3,786	26	1.30	4,273
Colorado	973	80	1.36	3,579
Connecticut	5,151	75	1.26	16,253
Delaware	1,678	100	1.26	7,060
Florida	6,616	78	1.95	33,600
Georgia	4,330	88	1.95	24,810
Idaho	109	77	1.33	373
Illinois	3,428	63	1.64	11,826
Indiana	4,041	75	1.64	16,596
Iowa	76	100	1.64	416
Kansas	214	50	1.64	586
Kentucky	220	54	1.45	575
Louisiana	3,533	62	1.95	14,262
Maine	4,067	94	1.26	16,084
Maryland	2,526	80	1.26	8,502
Massachusetts	5,319	91	1.26	20,364
Michigan	1,373	73	1.45	4,853
Minnesota	1,829	79	1.64	7,912
Mississippi	1,155	95	1.95	7,114
Missouri	396	77	1.64	1,670
Montana	543	4	1.36	99
Nebraska	34	0	1.55	0
Nevada	12	20	1.30	10
New Hampshire	1,406	93	1.26	5,501
New Jersey	6,013	96	1.26	24,286

(continued)

TABLE F-3 (continued)

State	Total residual oil consumption, 10^3 bbl	Consumption by boilers, %	Sulfur content, %	Sulfur content, tons
New Mexico	587	100	1.36	2,666
New York	5,034	55	1.26	11,648
North Carolina	5,445	89	1.95	31,553
North Dakota	9	83	1.55	39
Ohio	3,499	50	1.26	7,360
Oklahoma	331	83	1.57	1,440
Oregon	1,530	100	1.30	6,641
Pennsylvania	7,305	56	1.26	17,211
Rhode Island	937	100	1.26	3,942
South Carolina	2,345	77	1.95	11,757
South Dakota	51	77	1.55	203
Tennessee	237	100	1.95	1,543
Texas	5,704	97	1.65	30,483
Utah	2,737	10	1.35	1,234
Vermont	195	77	1.26	632
Virginia	6,501	96	1.26	26,257
Washington	2,968	95	1.30	12,239
West Virginia	834	43	1.26	1,509
Wisconsin	410	100	1.64	2,245
Wyoming	431	55	1.36	1,076
Alaska	574	100	1.30	2,492
Hawaii	187	68	1.30	552
Total	112,362		1.51	435,040

TABLE F-4. SULFUR CONTENT OF DISTILLATE OIL

State	Total distillate oil consumption, 10^3 bbl	Consumption by boilers, %	Sulfur content, %	Sulfur content, tons
Alabama	1,285	61	0.196	1,536
Arizona	2,694	61	0.275	4,519
Arkansas	628	61	0.245	939
California	4,174	61	0.282	7,180
Colorado	482	42	0.258	522
Connecticut	702	0	0.228	0
Delaware	377	61	0.228	524
Florida	1,220	35	0.196	837
Georgia	1,401	33	0.196	906
Idaho	789	61	0.258	1,242
Illinois	2,211	80	0.251	4,440
Indiana	2,023	53	0.251	269
Iowa	708	61	0.251	1,084
Kansas	168	61	0.251	257
Kentucky	1,181	100	0.240	2,834
Louisiana	1,984	61	0.196	2,372
Maine	303	61	0.228	421
Maryland	1,309	95	0.228	2,835
Massachusetts	823	0	0.228	0
Michigan	2,017	86	0.251	4,354
Minnesota	725	61	0.251	1,110
Mississippi	540	61	0.196	646
Missouri	1,059	100	0.251	2,658
Montana	1,236	61	0.258	1,945
Nebraska	240	61	0.253	370
Nevada	281	100	0.282	792
New Hampshire	94	0	0.228	0
New Jersey	2,329	41	0.228	2,177

(continued)

TABLE F-4 (continued)

State	Total distillate oil consumption, 10^3 bbl	Consumption by boilers, %	Sulfur content, %	Sulfur content, tons
New Mexico	798	0	0.258	0
New York	2,078	30	0.228	1,421
North Carolina	2,301	0	0.196	0
North Dakota	87	61	0.252	134
Ohio	5,362	65	0.228	7,946
Oklahoma	1,117	100	0.252	2,815
Oregon	1,640	0	0.282	0
Pennsylvania	4,331	91	0.228	8,986
Rhode Island	191	61	0.228	266
South Carolina	872	61	0.196	1,043
South Dakota	63	61	0.252	97
Tennessee	1,433	87	0.196	2,444
Texas	2,832	100	0.235	6,655
Utah	1,426	100	0.262	3,736
Vermont	79	0	0.228	0
Virginia	2,273	61	0.228	3,161
Washington	1,803	20	0.282	1,017
West Virginia	704	0	0.228	0
Wisconsin	477	65	0.251	778
Wyoming	680	79	0.258	1,386
Alaska	305	61	0.282	525
Hawaii	145	61	0.282	249
Total	63,953		0.23 (avg.)	91,850

Boiler	Particulate matter	SO_2	CO	Hydrocarbons	NO_x
Pulverized coal	16A	38S	1	0.3	18
Spreader stoker	13A	38S	2	1	15
Overfeed stoker	13A	38S	2	1	15
Underfeed stoker	2A	38S	10	3	6
Other stoker	5A	38S	10	3	6
Residual oil	10S+3	159S	5	1	60
Distillate oil	2	144S	5	1	22
Gas (industrial)	10	0.6	17	3	175
Gas (commercial)	10	0.6	20	8	100

A = percentage of ash   S = percentage of sulfur

Factors for coal are given as lb/ton of coal burned
Factors for oil are given as lb/10^3 gallons
Factors for gas are given as lb/10^6 ft^3

The factors for spreader stokers were assumed to apply to overfeed stokers. Factors for underfeed stokers were assumed to apply to "other stoker" firing except particulates, where a separate value was given. For oil burning, factors that were specified for SO_2 and SO_3 were combined. Where a range of values was given for gas-burning factors, the average value was used.

FUEL CONSUMPTION BY BOILER TYPE

For coal-burning boilers, the capacity data were distributed on the basis of the percentages from the Battelle design study (p. A21). Data for cast iron and fire-tube boilers are shown in Table F-5. Combined data for the water-tube, fire-tube, and cast iron boilers burning coal are shown in Table F-6. Table F-7 shows fuel consumption distributed in proportion to boiler capacity for each type of coal-burning boiler listed in column 3 of that table. The columns on the left of the table show uncontrolled emissions as calculated from the AP-42 factors for percentages of coal sulfur and ash. Sample calculations for boilers firing pulverized coal are shown below.

$$\text{Particulate matter (tons)} = \frac{16\ (13.4)\ 11236 \times 10^3}{2000}$$

$$= 1{,}204{,}500 \text{ tons}$$

$$= 1204 \times 10^3 \text{ tons}$$

TABLE F-5. DISTRIBUTION OF CAPACITY OF FIRE-TUBE AND CAST IRON BOILERS

	Capacity range, 10^6 Btu/h				
	<0.4	0.4 - 1.5	1.5 - 10	10 - 25	25 - 50
Total capacity of coal-fired fire-tube and cast iron boilers, 10^6 Btu/h	20,482	61,272	72,004	26,829	13,415
Distribution by type of coal burner, %					
Spreader stoker	nil	nil	7.5	15	20
Underfeed stoker	90	90	77.5	70	60
Overfeed stoker	5	5	10	10	15
Pulverized-coal-fired	0	0	0	0	0
Other	5	5	5	5	5
Distributed capacity of fire-tube and cast iron boilers, 10^6 Btu/h					
Spreader stoker	0	0	5,400	4,024	2,683
Underfeed stoker	18,434	55,145	55,800	18,780	8,049
Overfeed stoker	1,024	3,063	7,200	2,683	2,012
Pulverized-coal-fired	0	0	0	0	0
Other	1,024	3,064	3,600	1,342	671

Table F-6. TOTAL INDUSTRIAL/COMMERCIAL COAL-FIRED BOILER CAPACITY BY SIZE AND BURNER TYPE

Boiler type	Capacity range, 10^6 Btu/h									
	<0.4	0.4-1.5	1.5-10	10-25	25-50	50-100	100-250	250-500	500-1500	>1500
Pulverized-coal fired										
Capacity, 10^6 Btu/h	0	0	0	0	0	0	70,000	63,000	47,000	26,400
Percent of total	0	0	0	0	0	0	8.1	7.3	5.5	3.1
Spreader stoker										
Capacity, 10^6 Btu/h	0	0	6000	6400	22,600	25,400	73,700	25,600	7,700	6,300
Percent of total	0	0	0.7	0.7	2.6	3.0	8.6	3.0	0.9	0.7
Underfeed stoker										
Capacity, 10^6 Btu/h	18,400	55,700	64,500	13,700	65,200	71,000	25,700	11,900	3,800	3,100
Percent of total	2.1	6.5	7.5	1.6	7.6	8.3	3.0	1.4	0.4	0.4
Overfeed stoker										
Capacity, 10^6 Btu/h	1,000	3,100	8,200	63,200	17,100	18,300	12,900	8,000	2,500	2,100
Percent of total	0.1	0.4	1.0	7.3	2.0	2.1	1.5	0.9	0.3	0.2
Other										
Capacity, 10^6	1,000	3,100	3,800	1,300	700	0	0	0	0	0
Percent of total	0.1	0.4	0.4	0.2	0.1	0	0	0	0	0

TABLE F-7. UNCONTROLLED EMISSIONS FROM COAL-FIRED BOILERS

	Capacity, 10^6 Btu/h	Fraction of total coal-fired capacity	Coal consumption, 10^3 tons	Particulate matter	Emissions, 10^3 tons			
					SO_2	NO_x	HC	CO
Water-tube								
Pulverized coal	207,100	0.253	11,236	1204	427	101	1.7	5.6
Spreader stoker	161,600	0.198	8,795	766	334	66	4.4	8.8
Underfeed stoker	190,200	0.233	10,349	139	393	31	15.5	51.7
Overfeed stoker	61,130	0.075	3,331	290	127	25	1.7	3.3
Other stoker	0	0	0	0	0	0	0	0
Fire-tube								
Spreader stoker	8,954	0.011	489	43	19	4	0.2	0.5
Underfeed stoker	67,359	0.082	3,642	49	138	11	5.5	18.2
Overfeed stoker	8,652	0.011	489	16	19	4	0.25	0.5
Other stokers	4,471	0.005	222	7	8	2	0.3	1.1
Cast iron								
Spreader stoker	3,396	0.004	178	16	7	1	0.1	0.2
Underfeed stoker	91,363	0.112	4,975	67	189	15	7.5	24.9
Overfeed stoker	7,654	0.009	400	13	15	3	0.2	0.4
Other stokers	5,390	0.007	311	10	12	2	0.5	0.3
Total	817,269	1.000	44,417	2620	1,688	265	37.85	115.5

$$\begin{aligned} SO_x &= \frac{38(2)(11236)\ 10^3}{2000} \\ &= 426{,}968 \\ &= 427 \times 10^3 \text{ tons} \end{aligned}$$

$$\begin{aligned} NO_x &= \frac{18(11{,}236) \times 10^3}{2000} \\ &= 101{,}125 \\ &= 101 \times 10^3 \text{ tons} \end{aligned}$$

$$\begin{aligned} HC &= \frac{0.3(11{,}236) \times 10^3}{2000} \\ &= 1685 \\ &= 1.7 \times 10^3 \text{ tons} \end{aligned}$$

$$\begin{aligned} CO &= \frac{1(11{,}236) \times 10^3}{2000} \\ &= 5618 \\ &= 5.6 \times 10^3 \text{ tons} \end{aligned}$$

Tables F-8 and F-9 show distribution of capacity for boilers fired by residual oil and distillate oil. These tables also show consumption for these fuels distributed in proportion to capacity. Tables F-10 and F-11 show capacity and distributed fuel consumption by boiler type for commercial and industrial gas-fired boilers. The oil and gas capacity data were multiplied by the appropriate AP-42 emission factor to estimate emissions. Estimates for 1975 are presented in Section 3.2.

TABLE F-8. DISTRIBUTION OF CAPACITY AND CONSUMPTION OF RESIDUAL-OIL-FIRED BOILERS

Boiler type	Total boiler capacity firing residual oil, 10^6 Btu/h	Distribution, %	Corresponding fuel consumption, 10^3 bbl
Water-tube	759,100	62	173,706
Fire-tube	284,596	23	64,439
Cast iron	183,527	15	42,025
Total	1,227,223	100	280,170

TABLE F-9. DISTRIBUTION OF CAPACITY AND CONSUMPTION OF DISTILLATE-OIL-FIRED BOILERS

Boiler type	Total boiler capacity firing distillate oil, 10^6 Btu/h	Distribution, %	Corresponding fuel consumption, 10^3 bbl
Water-tube	134,800	31	60,066
Fire-tube	186,116	43	83,316
Cast iron	115,066	26	50,376
Total	436,066	100	193,758

TABLE F-10. DISTRIBUTION OF CAPACITY AND CONSUMPTION OF COMMERCIAL NATURAL-GAS-FIRED BOILERS

Boiler type	Total boiler capacity, 10^6 Btu/h	Distribution, %	Corresponding fuel consumption, 10^6 ft^3
Fire-tube	93,435	15.8	358,364
Water-tube	106,580	18.0	408,263
Cast iron	391,845	66.2	1,501,501
Total	591,860	100.0	2,268,128

TABLE F-11. DISTRIBUTION OF CAPACITY AND CONSUMPTION OF INDUSTRIAL NATURAL-GAS-FIRED BOILERS

Boiler type	Total boiler capacity, 10^6 Btu/h	Distribution, %	Corresponding fuel consumption, 10^6 ft^3
Fire-tube	379,585	26.8	589,248
Water-tube	939,320	66.3	1,457,730
Cast iron	98,000	6.9	151,710
Total	1,416,905	100.0	2,198,688

APPENDIX G

DETAILED CAPITAL AND ANNUALIZED COSTS FOR REPRESENTATIVE BOILERS

This appendix presents detailed cost estimates for 23 representative boiler/fuel combinations. For each boiler, two tables are provided: one gives detailed capital cost estimates, and the other gives detailed annualized cost estimates. The list of representative boilers and the cost tables associated with each is shown below:

Boiler	Fuel	Cost tables
Package Scotch fire-tube	Distillate oil	G-1, G-2
Package Scotch fire-tube	Natural gas	G-3, G-4
Package, underfeed stoker, water-tube	Eastern high-sulfur bituminous coal	G-5, G-6
Package, underfeed stoker, water-tube	Eastern low-sulfur bituminous coal	G-7, G-8
Package, underfeed stoker, water-tube	Western subbituminous coal	G-9, G-10
Field-erected, chain-grate-stoker, water-tube	Eastern high-sulfur bituminous coal	G-11, G-12
Field-erected, chain-grate-stoker, water-tube	Eastern low-sulfur coal	G-13, G-14
Field-erected chain-grate-stoker, water-tube	Western subbituminous coal	G-15, G-16
Package water-tube	Residual oil	G-17, G-18
Field-erected, spreader stoker, water-tube	Eastern high-sulfur bituminous coal	G-19, G-20
Field-erected, spreader stoker, water-tube	Eastern low-sulfur bituminous coal	G-21, G-22
Field-erected, spreader stoker, water-tube	Western subbituminous coal	G-23, G-24
Field-erected, pulverized coal, water-tube	Eastern high-sulfur bituminous coal	G-25, G-26

Boiler	Fuel	Cost tables
Field-erected, pulverized coal, water-tube	Eastern low-sulfur bituminous coal	G-27, G-28
Field-erected, pulverized coal, water-tube	Western subbituminous coal	G-29, G-30
Package, water-tube	Residual oil	G-31, G-32
Package, water-tube	Distillate oil	G-33, G-34
Package water-tube	Natural Gas	G-35, G-36
Field-erected, chain-grate stoker, water-tube	Eastern medium-sulfur coal	G-37, G-38
Field-erected, pulverized coal, water-tube	Eastern medium-sulfur coal	G-39, G-40
Field-erected, pulverized coal, water-tube	Eastern high-sulfur bituminous coal	G-41, G-42
Field-erected, pulverized coal, water-tube	Eastern low-sulfur bituminous coal	G-43, G-44
Field-erected, pulverized coal, water-tube	Western subbituminous coal	G-45, G-46

TABLE G-1. ESTIMATED CAPITAL COSTS OF A PACKAGE FIRE-TUBE BOILER FIRING DISTILLATE OIL WITH A THERMAL INPUT OF 4.4 MW (15×10^6 Btu/h; 300 hp; 150 psig/sat. temp. design)

CAPITAL COSTS

DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]	
Boiler (with fans and duct)	$ 36,100
Stack	2,700
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deaerator	4,000
Heaters	N.A.
Boiler feed pumps	6,100
Condensate systems	5,000
Water treating system	1,400
Chemical feed	Incl. w/boiler
Compressed air system	N.A.
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	16,000
Total Equipment Cost	$ 71,300
INSTALLATION COSTS, DIRECT	
Boiler (including foundations and steel)	$ 5,000
Stack	1,500
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deaerator	1,500
Heaters	N.A.
Boiler feed pumps	1,200
Condensate system	1,000
Water treating system	1,500
Chemical feed	400
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	3,000

(continued)

TABLE G-1 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	3,500
Duct work (not incl. w/boiler)	N.A.
Piping	20,000
Insulation	10,000
Painting	3,000
Electrical	15,000
Buildings	50,000
Total Installation Costs	$ 116,600
TOTAL DIRECT COSTS (Equipment + Installation)	$ 187,900
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 18,800
Construction and field expense (10% of direct costs)	18,800
Construction fees (10% of direct costs)	18,800
Startup (2% of direct costs)	3,800
Performance tests (minimum $2000)	2,000
TOTAL INDIRECT COSTS	$ 62,200
Contingencies (20% of direct and indirect costs)	$ 50,000
Total turnkey costs (Direct + Indirect + Contingencies)	$ 300,100
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 103,000
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 405,100

[a] Quote from Cleaver-Brooks, May 11, 1978.
N.A. - Not applicable.

TABLE G-2. ESTIMATED ANNUALIZED COSTS OF A PACKAGE, FIRE-TUBE BOILER FIRING DISTILLATE OIL WITH A THERMAL INPUT OF 4.4 MW (15×10^6 Btu/h; 300 hp; 150 psig/sat. temp. design)

DIRECT COST	
Direct labor	$ 105,300
Supervision	68,500
Maintenance labor	32,000
Maintenance materials	a
Replacement parts	15,000
Electricity	11,600
Steam	N.A.
Cooling water	N.A.
Process water	200
Fuel	177,400
Bottom ash disposal	N.A.
Chemicals	2,000
Total direct cost	$ 412,000
OVERHEAD	
Payroll (30% of direct labor)	$ 31,600
Plant (26% of labor, parts & maint.)	57,400
Total overhead costs	$ 89,000
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 12,000
Capital recovery factor (11.75% of total turnkey costs)	35,300
Interest on working capital (10% of working capital)	10,300
Total capital charges	$ 57,600
TOTAL ANNUALIZED COSTS	$ 558,600

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-3. ESTIMATED CAPITAL COSTS OF A PACKAGE, FIRE-TUBE BOILER FIRING NATURAL GAS WITH A THERMAL INPUT OF 4.4 MW (15 x 10 Btu/h; 300 hp; 150 psig/sat. temp. design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]

Boiler (with fans and ducts)	$ 36,100
Stack	2,700
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deaerator	4,000
Heaters	N.A.
Boiler feed pumps	6,100
Condensate systems	5,000
Water treating system	1,400
Chemical feed	Incl. w/boiler
Compressed air system	N.A.
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	16,000
Total Equipment Cost	$ 71,300

INSTALLATION COSTS, DIRECT

Boiler (including foundations and steel)	$ 5,000
Stack	1,500
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deaerator	1,500
Heaters	N.A.
Boiler feed pumps	1,200
Condensate system	1,000
Water treating system	1,500
Chemical feed	400
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	3,000

(continued)

TABLE G-3 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	3,500
Duct work (not incl. w/boiler)	N.A.
Piping	20,000
Insulation	10,000
Painting	3,000
Electrical	15,000
Buildings	50,000
Total Installation Costs	$ 116,600
TOTAL DIRECT COSTS (Equipment + Installation)	$ 187,900
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 18,800
Construction and field expense (10% of direct costs)	18,800
Construction fees (10% of direct costs)	18,800
Startup (2% of direct costs)	3,800
Performance tests (minimum $2000)	2,000
TOTAL INDIRECT COSTS	$ 62,200
Contingencies (20% of direct and indirect costs)	$ 50,000
Total turnkey costs (Direct + Indirect + Contingencies)	$ 300,100
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 87,700
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 389,800

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[a] Quote from Cleaver-Brooks, May 11, 1978.

N.A. - Not applicable.

TABLE G-4. ESTIMATED ANNUALIZED COSTS OF A PACKAGE,FIRE-TUBE BOILER FIRING NATURAL GAS WITH A THERMAL INPUT OF 4.4 MW (15×10^6 Btu/h; 300 hp; 150 psig/sat. temp. design)

DIRECT COST	
Direct labor	$ 105,300
Supervision	68,500
Maintenance labor	32,000
Maintenance materials	a
Replacement parts	15,000
Electricity	11,600
Steam	N.A.
Cooling water	N.A.
Process water	200
Fuel	115,300
Bottom ash disposal	N.A.
Chemicals	3,000
Total direct cost	$ 350,900
OVERHEAD	
Payroll (30% of direct labor)	$ 31,600
Plant (26% of labor, parts & maint.)	57,400
Total overhead costs	$ 89,000
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 12,000
Capital recovery factor (11.75% of total turnkey costs)	35,300
Interest on working capital (10% of working capital)	8,800
Total capital charges	$ 56,100
TOTAL ANNUALIZED COSTS	$ 496,000

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-5. ESTIMATED CAPITAL COSTS OF A PACKAGE, WATER-TUBE, UNDERFEED-STOKER BOILER FIRING EASTERN HIGH-SULFUR COAL WITH A THERMAL INPUT OF 8.8 MW (30×10^6 Btu/h; 150 psig/sat. temp. design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]	
Boiler (with fans and ducts)	$ 308,900
Stack	3,000
Instrumentation	Incl. w/boiler
Stokers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	5,200
Heaters	N.A.
Boiler feed pumps	13,400
Condensate systems	7,700
Water treating system	8,000
Chemical feed	1,400
Compressed air system	N.A.
Coal handling system	136,700
Ash disposal system	99,500
Thawing equipment	N.A.
Fuel-oil system	N.A.
Total Equipment Cost	$ 583,800
INSTALLATION COSTS, DIRECT	
Boiler (including foundations and steel)	$ 105,300
Stack	1,500
Instrumentation	Incl. w/boiler
Pulverizers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	2,500
Heaters	N.A.
Boiler feed pumps	3,000
Condensate system	1,100
Water treating system	2,000
Chemical feed	800
Coal handling system	81,900
Ash disposal system	41,000
Thawing equipment	N.A.
Fuel-oil system	N.A.

(continued)

TABLE G-5 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	35,100
Duct work (not incl. w/boiler)	N.A.
Piping	41,000
Insulation	29,300
Painting	5,900
Electrical	30,000
Buildings	140,400
Total Installation Costs	$ 520,800
TOTAL DIRECT COSTS (Equipment + Installation)	$ 1,104,600
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 110,500
Construction and field expense (10% of direct costs)	110,500
Construction fees (10% of direct costs)	110,500
Startup (2% of direct costs)	22,100
Performance tests (minimum $2000)	3,500
TOTAL INDIRECT COSTS	$ 357,100
Contingencies (20% of direct and indirect costs)	$ 292,300
Total turnkey costs (Direct + Indirect + Contingencies)	$ 1,754,000
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 135,300
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 1,891,300

[a] Quote from Zurn Industries, Inc., May 25, 1978.

N.A. - Not applicable.

TABLE G-6. ESTIMATED ANNUALIZED COSTS OF A PACKAGE, WATER-TUBE UNDERFEED-STOKER BOILER FIRING EASTERN HIGH-SULFUR COAL WITH A THERMAL INPUT OF 8.8 MW
(30 x 10^6 Btu/h; 150 psig/sat. temp. design)

DIRECT COST	
Direct labor	$ 157,900
Supervision	68,500
Maintenance labor	64,100
Maintenance materials	a
Replacement parts	70,200
Electricity	40,100
Steam	N.A.
Cooling water	N.A.
Process water	500
Fuel	116,700
Bottom ash disposal	21,000
Chemicals	2,300
Total direct cost	$ 541,300
OVERHEAD	
Payroll (30% of direct labor)	$ 47,400
Plant (26% of labor, parts & maint.)	93,800
Total overhead costs	$ 141,200
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 70,200
Capital recovery factor (10.61 % of total turnkey costs)	186,100
Interest on working capital (10% of working capital)	13,500
Total capital charges	$ 269,800
TOTAL ANNUALIZED COSTS	$ 952,300

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-7. ESTIMATED CAPITAL COSTS OF A PACKAGE, WATER-TUBE, UNDERFEED-STOKER BOILER FIRING EASTERN LOW-SULFUR COAL WITH A THERMAL INPUT OF 8.8 MW (30×10^6 Btu/h; 150 psig/sat. temp. design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]	
Boiler (with fans and duct)	$ 264,000
Stack	3,000
Instrumentation	Incl. w/boiler
Stokers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	5,200
Heaters	N.A.
Boiler feed pumps	13,400
Condensate systems	7,700
Water treating system	8,000
Chemical feed	1,400
Compressed air system	N.A.
Coal handling system	116,800
Ash disposal system	85,000
Thawing equipment	N.A.
Fuel-oil system	N.A.
Total Equipment Cost	$ 504,500
INSTALLATION COSTS, DIRECT	
Boiler (including foundations and steel)	$ 90,000
Stack	1,500
Instrumentation	Incl. w/boiler
Pulverizers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	2,500
Heaters	N.A.
Boiler feed pumps	3,000
Condensate system	1,100
Water treating system	2,000
Chemical feed	800
Coal handling system	70,000
Ash disposal system	35,000
Thawing equipment	N.A.
Fuel-oil system	N.A.

(continued)

TABLE G-7 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	30,000
Duct work (not incl. w/boiler)	N.A.
Piping	35,000
Insulation	25,000
Painting	5,000
Electrical	30,000
Buildings	120,000
Total Installation Costs	$ 450,900
TOTAL DIRECT COSTS (Equipment + Installation)	$ 955,400
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 95,500
Construction and field expense (10% of direct costs)	95,500
Construction fees (10% of direct costs)	95,500
Startup (2% of direct costs)	19,100
Performance tests (minimum $2000)	3,500
TOTAL INDIRECT COSTS	$ 309,100
Contingencies (20% of direct and indirect costs)	$ 252,900
Total turnkey costs (Direct + Indirect + Contingencies)	$ 1,517,400
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 145,800
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 1,665,200

[a] Quote from Zurn Industries, Inc., May 25, 1978.

N.A. - Not applicable.

TABLE G-8. ESTIMATED ANNUALIZED COSTS OF A PACKAGE, WATER-TUBE, UNDERFEED-STOKER BOILER FIRING EASTERN LOW-SULFUR COAL WITH A THERMAL INPUT OF 8.8 MW

(30 x 10^6 Btu/h; 150 psig/sat. temp. design)

DIRECT COST	
Direct labor	$ 157,900
Supervision	68,500
Maintenance labor	64,100
Maintenance materials	a
Replacement parts	60,000
Electricity	34,300
Steam	N.A.
Cooling water	N.A.
Process water	500
Fuel	182,900
Bottom ash disposal	12,600
Chemicals	2,300
Total direct cost	$ 583,100
OVERHEAD	
Payroll (30% of direct labor)	$ 47,400
Plant (26% of labor, parts & maint.)	91,100
Total overhead costs	$ 138,500
BY-PRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 60,700
Capital recovery factor (10.61% of total turnkey costs)	161,000
Interest on working capital (10% of working capital)	14,600
Total capital charges	$ 236,300
TOTAL ANNUALIZED COSTS	$ 957,900

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-9. ESTIMATED CAPITAL COSTS OF A PACKAGE, WATER-TUBE, UNDERFEED-STOKER BOILER FIRING SUBBITUMINOUS COAL WITH A THERMAL INPUT OF 8.8 MW (30×10^6 Btu/h; 150 psig/sat. temp. design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]	
Boiler (with fans and ducts)	$ 380,200
Stack	3,000
Instrumentation	Incl. w/boiler
Stokers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	5,200
Heaters	N.A.
Boiler feed pumps	13,400
Condensate systems	7,700
Water treating system	8,000
Chemical feed	1,400
Compressed air system	N.A.
Coal handling system	168,200
Ash disposal system	122,400
Thawing equipment	N.A.
Fuel-oil system	N.A.
Total Equipment Cost	$ 709,500
INSTALLATION COSTS, DIRECT	
Boiler (including foundations and steel)	$ 129,600
Stack	1,500
Instrumentation	Incl. w/boiler
Stokers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	2,500
Heaters	N.A.
Boiler feed pumps	3,000
Condensate system	1,100
Water treating system	2,000
Chemical feed	800
Coal handling system	100,800
Ash disposal system	50,400
Thawing equipment	N.A.
Fuel-oil system	N.A.

(continued)

TABLE G-9 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	$ 43,200
Duct work (not incl. w/boiler)	N.A.
Piping	50,400
Insulation	36,000
Painting	7,200
Electrical	30,000
Buildings	172,800
Total Installation Costs	$ 631,300
TOTAL DIRECT COSTS (Equipment + Installation)	$ 1,340,800
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 134,100
Construction and field expense (10% of direct costs)	134,100
Construction fees (10% of direct costs)	134,100
Startup (2% of direct costs)	26,800
Performance tests (minimum $2000)	3,500
TOTAL INDIRECT COSTS	$ 432,600
Contingencies (20% of direct and indirect costs)	$ 354,700
Total turnkey costs (Direct + Indirect + Contingencies)	$ 2,128,100
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 127,000
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 2,257,100

[a] Quote from Zurn Industries, Inc., May 25, 1978.

N.A. - Not applicable.

TABLE G-10. ESTIMATED ANNUALIZED COSTS OF A PACKAGE, WATER-TUBE, UNDERFEED-STOKER BOILER FIRING SUBBITUMINOUS COAL WITH A THERMAL INPUT OF 8.8 MW (30×10^6 Btu/h; 150 psig/sat. temp. design)

DIRECT COST	
Direct labor	$ 157,900
Supervision	68,500
Maintenance labor	64,100
Maintenance materials	a
Replacement parts	86,400
Electricity	49,400
Steam	N.A.
Cooling water	N.A.
Process water	500
Fuel	66,200
Bottom ash disposal	12,600
Chemicals	2,300
Total direct cost	$ 507,900
OVERHEAD	
Payroll (30% of direct labor)	$ 47,400
Plant (26% of labor, parts & maint.)	98,000
Total overhead costs	$ 145,400
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 85,100
Capital recovery factor (10.61% of total turnkey costs)	225,800
Interest on working capital (10% of working capital)	12,700
Total capital charges	$ 323,600
TOTAL ANNUALIZED COSTS	$ 976,900

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-11. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, CHAIN-GRATE-STOKER BOILER FIRING EASTERN HIGH-SULFUR COAL WITH A THERMAL INPUT OF 22 MW

(75 x 10^6 Btu/h; 150 psig/sat. temp. design)

CAPITAL COSTS

DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]	
Boiler (with fans and duct)	$ 760,500
Stack	80,000
Instrumentation	50,000
Stokers	150,000
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	15,900
Heaters	N.A.
Boiler feed pumps	25,300
Condensate systems	8,700
Water treating system	15,000
Chemical feed	1,400
Compressed air system	N.A.
Coal handling system	165,400
Ash disposal system	136,000
Thawing equipment	N.A.
Fuel-oil system	N.A.
Total Equipment Cost	$1,408,200
INSTALLATION COSTS, DIRECT	
Boiler (including foundations and steel)	$ 491,400
Stack	20,000
Instrumentation	15,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	3,500
Heaters	N.A.
Boiler feed pumps	5,500
Condensate system	1,300
Water treating system	2,500
Chemical feed	1,500
Coal handling system	175,500
Ash disposal system	70,200
Thawing equipment	N.A.
Fuel-oil system	N.A.

(continued)

TABLE G-11 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	93,600
Duct work (not incl. w/boiler)	N.A.
Piping	58,500
Insulation	46,800
Painting	8,200
Electrical	75,000
Buildings	234,000
Total Installation Costs	$ 1,302,500
TOTAL DIRECT COSTS (Equipment + Installation)	$ 2,710,700
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 271,100
Construction and field expense (10% of direct costs)	271,100
Construction fees (10% of direct costs)	271,100
Startup (2% of direct costs)	54,200
Performance tests (minimum $2000)	7,000
TOTAL INDIRECT COSTS	$ 874,500
Contingencies (20% of direct and indirect costs)	$ 717,000
Total turnkey costs (Direct + Indirect + Contingencies)	$ 4,302,200
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 250,200
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 4,554,400

[a] Quote from Zurn Industries, Inc., May 25, 1978.

N.A. - Not applicable.

TABLE G-12. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE CHAIN-GRATE-STOKER BOILER FIRING EASTERN HIGH-SULFUR COAL WITH A THERMAL INPUT OF 22 MW

(75 x 10^6 Btu/h; 150 psig/sat. temp. design)

DIRECT COST	
Direct labor	$ 210,600
Supervision	136,900
Maintenance labor	128,200
Maintenance materials	a
Replacement parts	117,000
Electricity	57,600
Steam	N.A.
Cooling water	N.A.
Process water	1,100
Fuel	291,700
Bottom ash disposal	52,600
Chemicals	4,900
Total direct cost	$1,000,600
OVERHEAD	
Payroll (30% of direct labor)	$ 63,200
Plant (26% of labor, parts & maint.)	154,100
Total overhead costs	$ 217,300
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 172,100
Capital recovery factor (10.14% of total turnkey costs)	436,200
Interest on working capital (10% of working capital)	25,000
Total capital charges	$ 633,300
TOTAL ANNUALIZED COSTS	$ 1,851,200

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-13. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE CHAIN-GRATE-STOKER BOILER FIRING EASTERN LOW-SULFUR COAL WITH A THERMAL INPUT OF 22 MW (75×10^6 Btu/h; 150 psig/sat. temp. design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]

Boiler (with fans and ducts)	$ 650,000
Stack	80,000
Instrumentation	50,000
Stoker	150,000
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	15,900
Heaters	N.A.
Boiler feed pumps	25,300
Condensate systems	8,700
Water treating system	15,000
Chemical feed	1,400
Compressed air system	N.A.
Coal handling system	141,400
Ash disposal system	116,200
Thawing equipment	N.A.
Fuel-oil system	N.A.
Total Equipment Cost	$1,253,900

INSTALLATION COSTS, DIRECT

Boiler (including foundations and steel)	$ 420,000
Stack	20,000
Instrumentation	15,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	3,500
Heaters	N.A.
Boiler feed pumps	5,500
Condensate system	1,300
Water treating system	2,500
Chemical feed	1,500
Coal handling system	150,000
Ash disposal system	60,000
Thawing equipment	N.A.
Fuel-oil system	N.A.

(continued)

TABLE G-13 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	80,000
Duct work (not incl. w/boiler)	N.A.
Piping	50,000
Insulation	40,000
Painting	7,000
Electrical	75,000
Buildings	200,000
Total Installation Costs	$ 1,131,300
TOTAL DIRECT COSTS (Equipment + Installation)	$ 2,385,200
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 238,500
Construction and field expense (10% of direct costs)	238,500
Construction fees (10% of direct costs)	238,500
Startup (2% of direct costs)	47,700
Performance tests (minimum $2000)	7,000
TOTAL INDIRECT COSTS	$ 770,200
Contingencies (20% of direct and indirect costs)	$ 631,100
Total turnkey costs (Direct + Indirect + Contingencies)	$ 3,786,500
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 279,400
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 4,067,900

[a] Quote from Zurn Industries, Inc., May 25, 1978.

N.A. - Not applicable.

TABLE G-14. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE, CHAIN-GRATE-STOKER BOILER FIRING EASTERN LOW-SULFUR COAL WITH A THERMAL INPUT OF 22 MW

(75 x 10^6 Btu/h; 150 psig/sat. temp. design)

DIRECT COST	
Direct labor	$ 210,600
Supervision	136,900
Maintenance labor	128,200
Maintenance materials	[a]
Replacement parts	100,000
Electricity	49,200
Steam	N.A.
Cooling water	N.A.
Process water	1,100
Fuel	457,300
Bottom ash disposal	29,400
Chemicals	4,900
Total direct cost	$1,117,600
OVERHEAD	
Payroll (30% of direct labor)	$ 63,200
Plant (26% of labor, parts & maint.)	149,700
Total overhead costs	$ 212,900
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 151,500
Capital recovery factor (10.14% of total turnkey costs)	384,000
Interest on working capital (10% of working capital)	27,900
Total capital charges	$ 563,400
TOTAL ANNUALIZED COSTS	$1,893,900

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-15. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, CHAIN-GRATE-STOKER-BOILER FIRING SUBBITUMINOUS COAL WITH A THERMAL INPUT OF 22 MW

(75 x 10^6 Btu/h; 150 psig/sat. temp. design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]	
Boiler (with fans and ducts)	$ 936,000
Stack	80,000
Instrumentation	50,000
Stokers	150,000
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	15,900
Heaters	N.A.
Boiler feed pumps	25,300
Condensate systems	8,700
Water treating system	15,000
Chemical feed	1,400
Compressed air system	N.A.
Coal handling system	203,600
Ash disposal system	167,300
Thawing equipment	N.A.
Fuel-oil system	N.A.
Total Equipment Cost	$1,653,200
INSTALLATION COSTS, DIRECT	
Boiler (including foundations and steel)	$ 601,000
Stack	20,000
Instrumentation	15,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	3,500
Heaters	N.A.
Boiler feed pumps	5,500
Condensate system	1,300
Water treating system	2,500
Chemical feed	1,500
Coal handling system	216,000
Ash disposal system	86,400
Thawing equipment	N.A.
Fuel-oil system	N.A.

(continued)

TABLE G -15 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	115,200
Duct work (not incl. w/boiler)	N.A.
Piping	72,000
Insulation	57,600
Painting	10,100
Electrical	75,000
Buildings	288,000
Total Installation Costs	$ 1,570,600
TOTAL DIRECT COSTS (Equipment + Installation)	$ 3,223,800
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 322,400
Construction and field expense (10% of direct costs)	322,400
Construction fees (10% of direct costs)	322,400
Startup (2% of direct costs)	64,500
Performance tests (minimum $2000)	7,000
TOTAL INDIRECT COSTS	$ 1,038,700
Contingencies (20% of direct and indirect costs)	$ 852,500
Total turnkey costs (Direct + Indirect + Contingencies)	$ 5,115,000
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 224,000
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 5,341,000

[a] Quote from Zurn Industries, Inc., May 25, 1978.

N.A. - Not applicable.

TABLE G-16. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE, CHAIN-GRATE-STOKER BOILER FIRING SUBBITUMINOUS COAL WITH A THERMAL INPUT OF 22.0 MW

(75 x 10^6 Btu/h; 150 psig/sat. temp. design)

DIRECT COST	
Direct labor	$ 210,600
Supervision	136,900
Maintenance labor	128,200
Maintenance materials	a
Replacement parts	144,000
Electricity	70,900
Steam	N.A.
Cooling water	N.A.
Process water	1,100
Fuel	165,600
Bottom ash disposal	33,600
Chemicals	4,900
Total direct cost	$ 895,800
OVERHEAD	
Payroll (30% of direct labor)	$ 63,200
Plant (26% of labor, parts & maint.)	161,100
Total overhead costs	$ 224,300
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 204,600
Capital recovery factor (10.14% of total turnkey costs)	518,700
Interest on working capital (10% of working capital)	22,400
Total capital charges	$ 745,700
TOTAL ANNUALIZED COSTS	$ 1,865,800

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-17. ESTIMATED CAPITAL COSTS OF A PACKAGE, WATER-TUBE, RESIDUAL OIL-FIRED BOILER WITH A THERMAL INPUT OF 44 MW (150 x 10^6 Btu/h; 750 psig/750°F design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]	
Boiler (with fans and ducts)	$ 600,000
Stack	14,500
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deareator	21,600
Heaters	N.A.
Boiler feed pumps	53,600
Condensate systems	6,700
Water treating system	18,000
Chemical feed	1,500
Compressed air system	N.A.
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	50,000
Total Equipment Cost	$ 765,900
INSTALLATION COSTS, DIRECT	
Boiler (including foundations and steel)	$ 20,000
Stack	6,500
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deaerator	4,000
Heaters	N.A.
Boiler feed pumps	7,500
Condensate system	1,500
Water treating system	3,000
Chemical feed	500
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	20,000

(continued)

TABLE G-17 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	30,000
Duct work (not incl. w/boiler)	N.A.
Piping	65,000
Insulation	20,000
Painting	5,000
Electrical	40,000
Buildings	100,000
Total Installation Costs	$ 323,000
TOTAL DIRECT COSTS (Equipment + Installation)	$ 1,088,900
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 108,900
Construction and field expense (10% of direct costs)	108,900
Construction fees (10% of direct costs)	108,900
Startup (2% of direct costs)	21,800
Performance tests (minimum $2000)	3,500
TOTAL INDIRECT COSTS	$ 352,000
Contingencies (20% of direct and indirect costs)	$ 288,200
Total turnkey costs (Direct + Indirect + Contingencies)	$ 1,729,100
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 513,800
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 2,244,900

[a] Quote from Zurn Industries, Inc., May 25, 1978.

N.A. - Not applicable.

TABLE G-18. ESTIMATED ANNUALIZED COSTS OF A PACKAGE, WATER-TUBE, RESIDUAL OIL-FIRED BOILER WITH A THERMAL INPUT OF 44 MW (150 X 10^6 Btu/h; 750 psig/750°F design)

DIRECT COST	
Direct labor	$ 210,600
Supervision	68,500
Maintenance labor	64,100
Maintenance materials	[a]
Replacement parts	60,000
Electricity	47,100
Steam	N.A.
Cooling water	N.A.
Process water	2,100
Fuel	1,597,200
Bottom ash disposal	N.A.
Chemicals	5,500
Total direct cost	$ 2,055,100
OVERHEAD	
Payroll (30% of direct labor)	$ 63,200
Plant (26% of labor, parts & maint.)	104,800
Total overhead costs	$ 168,000
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 69,200
Capital recovery factor (10.61% of total turnkey costs)	183,500
Interest on working capital (10% of working capital)	51,400
Total capital charges	$ 304,100
TOTAL ANNUALIZED COSTS	$ 2,527,200

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-19. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, SPREADER-STOKER BOILER FIRING HIGH-SULFUR EASTERN COAL WITH A THERMAL INPUT OF 44 MW

(150 x 10^6 Btu/h; 450 psig/500°F design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]

Boiler (with fans and ducts)	$ 1,753,800
Stack	300,000
Instrumentation	113,500
Stokers	227,600
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	21,600
Heaters	N.A.
Boiler feed pumps	44,500
Condensate systems	9,200
Water treating system	18,000
Chemical feed	1,500
Compressed air system	N.A.
Coal handling system	282,300
Ash disposal system	167,500
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.
Total Equipment Cost	$ 2,939,500

INSTALLATION COSTS, DIRECT

Boiler (including foundations and steel)	$ 936,000
Stack	50,000
Instrumentation	25,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	4,000
Heaters	N.A.
Boiler feed pumps	7,000
Condensate system	1,500
Water treating system	3,000
Chemical feed	1,500
Coal handling system	292,500 (incl. site prep.)
Ash disposal system	117,000
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.

(continued)

TABLE G-19 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	175,500
Duct work (not incl. w/boiler)	N.A.
Piping	81,900
Insulation	87,800
Painting	11,700
Electrical	150,000
Buildings	409,500
Total Installation Costs	$ 2,353,900
TOTAL DIRECT COSTS (Equipment + Installation)	$ 5,293,400
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 529,300
Construction and field expense (10% of direct costs)	529,300
Construction fees (10% of direct costs)	529,300
Startup (2% of direct costs)	105,900
Performance tests	10,000
TOTAL INDIRECT COSTS	$ 1,703,800
Contingencies (20% of direct and indirect costs)	$ 1,399,400
Total turnkey costs (Direct + Indirect + Contingencies)	$ 8,396,600
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 385,600
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 8,784,200

[a] Quote from Babcock & Wilcox, Inc., August 17, 1978.

N.A. - Not applicable.

TABLE G-20. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED WATER-TUBE, SPREADER-STOKER BOILER FIRING HIGH-SULFUR EASTERN COAL WITH A THERMAL INPUT OF 44 MW
(150 x 10^6 Btu/h; 450 psig/600°F design)

DIRECT COST	
Direct labor	$ 315,900
Supervision	136,900
Maintenance labor	128,200
Maintenance materials	a
Replacement parts	234,000
Electricity	85,200
Steam	N.A.
Cooling water	N.A.
Process water	2,300
Fuel	583,400
Bottom ash disposal	50,500
Chemicals	6,000
Total direct cost	$1,542,400
OVERHEAD	
Payroll (30% of direct labor)	$ 94,800
Plant (26% of labor, parts & maint.)	211,900
Total overhead costs	$ 306,700
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 335,900
Capital recovery factor (10.14% of total turnkey costs)	851,400
Interest on working capital (10% of working capital)	38,600
Total capital charges	$1,225,900
TOTAL ANNUALIZED COSTS	$3,075,000

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-21. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, SPREADER-STOKER BOILER FIRING LOW-SULFUR EASTERN COAL WITH A THERMAL INPUT OF 44 MW (150×10^6 Btu/h; 450 psig/600°F design)

CAPITAL COSTS

DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST [a]	
Boiler (with fans and ducts)	$ 1,499,000
Stack	300,000
Instrumentation	113,500
Stokers	194,500
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	21,600
Heaters	N.A.
Boiler feed pumps	44,500
Condensate systems	9,200
Water treating system	18,000
Chemical feed	1,500
Compressed air system	N.A.
Coal handling system	241,300
Ash disposal system	143,200
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.
Total Equipment Cost	$ 2,586,300
INSTALLATION COSTS, DIRECT	
Boiler (including foundations and steel)	$ 800,000
Stack	50,000
Instrumentation	25,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	4,000
Heaters	N.A.
Boiler feed pumps	7,000
Condensate system	1,500
Water treating system	3,000
Chemical feed	1,500
Coal handling system	250,000 (incl. site prep.)
Ash disposal system	100,000
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.

(continued)

TABLE G-21 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	150,000
Duct work (not incl. w/boiler)	N.A.
Piping	70,000
Insulation	75,000
Painting	10,000
Electrical	150,000
Buildings	350,000
Total Installation Costs	$ 2,047,000
TOTAL DIRECT COSTS (Equipment + Installation)	$ 4,633,300
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 463,300
Construction and field expense (10% of direct costs)	463,300
Construction fees (10% of direct costs)	463,300
Startup (2% of direct costs)	92,700
Performance tests (minimum $2000)	10,000
TOTAL INDIRECT COSTS	$ 1,492,600
Contingencies (20% of direct and indirect costs)	$ 1,225,200
Total turnkey costs (Direct + Indirect + Contingencies)	$ 7,351,100
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 451,000
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 7,804,100

[a] Quote from Babcock & Wilcox, Inc., August 17, 1978.

N.A. - Not applicable.

TABLE G-22. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE, SPREADER-STOKER BOILER FIRING LOW-SULFUR EASTERN COAL WITH A THERMAL INPUT OF 44 MW (150×10^6 Btu/h; 450 psig/600°F design)

DIRECT COST	
Direct labor	$ 315,900
Supervision	136,900
Maintenance labor	128,200
Maintenance materials	a
Replacement parts	200,000
Electricity	72,800
Steam	N.A.
Cooling water	N.A.
Process water	2,300
Fuel	914,500
Bottom ash disposal	27,300
Chemicals	6,000
Total direct cost	$1,803,900
OVERHEAD	
Payroll (30% of direct labor)	$ 94,800
Plant (26% of labor, parts & maint.)	203,100
Total overhead costs	$ 297,900
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 294,000
Capital recovery factor (10.14% of total turnkey costs)	745,400
Interest on working capital (10% of working capital)	45,100
Total capital charges	$ 1,084,500
TOTAL ANNUALIZED COSTS	$ 3,186,300

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-23. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, SPREADER-STOKER BOILER FIRING SUBBITUMINOUS COAL WITH A THERMAL INPUT OF 44 MW
(150 x 10^6 Btu/h; 450 psig/600°F design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]

Boiler (with fans and ducts)	$ 2,158,600
Stack	300,000
Instrumentation	113,500
Stokers	280,100
Feeders	Incl. w/coal handing
Crushers	Incl. w/coal handling
Deaerator	21,600
Heaters	N.A.
Boiler feed pumps	44,500
Condensate systems	9,200
Water treating system	18,000
Chemical feed	1,500
Compressed air system	N.A.
Coal handling system	347,500
Ash disposal system	206,200
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.
Total Equipment Cost	$ 3,500,700

INSTALLATION COSTS, DIRECT

Boiler (including foundations and steel)	$ 1,152,000
Stack	50,000
Instrumentation	25,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	4,000
Heaters	N.A.
Boiler feed pumps	7,000
Condensate system	1,500
Water treating system	3,000
Chemical feed	1,500
Coal handling system	360,000 (incl. site prep.)
Ash disposal system	144,000
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.

(continued)

TABLE G-23 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	216,000
Duct work (not incl. w/boiler)	N.A.
Piping	100,800
Insulation	108,000
Painting	14,400
Electrical	150,000
Buildings	504,000
Total Installation Costs	$ 2,841,200
TOTAL DIRECT COSTS (Equipment + Installation)	$ 6,341,900
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 634,200
Construction and field expense (10% of direct costs)	634,200
Construction fees (10% of direct costs)	634,200
Startup (2% of direct costs)	126,800
Performance tests (minimum $2000)	10,000
TOTAL INDIRECT COSTS	$ 2,039,400
Contingencies (20% of direct and indirect costs)	$ 1,676,300
Total turnkey costs (Direct + Indirect + Contingencies)	$10,057,600
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 336,200
GRAND TOTAL (Turnkey + Land + Working Capital)	$10,395,800

[a] Quote from Babcock & Wilcox, Inc., August 17, 1978.

N.A. - Not applicable.

TABLE G-24. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE, SPREADER-STOKER BOILER FIRING SUBBITUMINOUS COAL WITH A THERMAL INPUT OF 44 MW

(150 x 10^6 Btu/h; 450 psig/600°F design)

DIRECT COST	
Direct labor	$ 315,900
Supervision	136,900
Maintenance labor	128,200
Maintenance materials	a
Replacement parts	288,000
Electricity	104,800
Steam	N.A.
Cooling water	N.A.
Process water	2,300
Fuel	331,100
Bottom ash disposal	31,500
Chemicals	6,000
Total direct cost	$1,344,700
OVERHEAD	
Payroll (30% of direct labor)	$ 94,800
Plant (26% of labor, parts & maint.)	225,900
Total overhead costs	$ 320,700
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 402,300
Capital recovery factor (10.14% of total turnkey costs)	1,019,800
Interest on working capital (10% of working capital)	33,600
Total capital charges	$ 1,455,700
TOTAL ANNUALIZED COSTS	$ 3,121,100

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-25. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING EASTERN HIGH-SULFUR COAL WITH A THERMAL INPUT OF 58.6 MW (200×10^6 Btu/h; 750 psig/750°F design)

CAPITAL COSTS

DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST [a]

Boiler (with fans and ducts)	$ 2,492,100
Stack	365,000
Instrumentation	228,000
Pulverizers	613,100
Feeders	128,700
Crushers	Incl. w/coal handling
Deaerator	29,000
Heaters	Incl. w/boiler
Boiler feed pumps	58,000
Condensate systems	16,300
Water treating system	20,000
Chemical feed	1,500
Compressed air system	23,400
Coal handling system	308,800
Ash disposal system	210,600
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.
Total Equipment Cost	$ 4,494,500

INSTALLATION COSTS, DIRECT

Boiler (including foundations and steel)	$ 1,270,000
Stack	60,000
Instrumentation	35,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/boiler
Crushers	Incl. w/coal handling
Deaerator	5,000
Heaters	Incl. w/boiler
Boiler feed pumps	8,000
Condensate system	2,000
Water treating system	3,500
Chemical feed	1,500
Coal handling system	321,800(incl. site prep.)
Ash disposal system	140,400
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.

(continued)

TABLE G-25 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	210,600
Duct work (not incl. w/boiler)	N.A.
Piping	93,600
Insulation	93,600
Painting	11,700
Electrical	160,000
Buildings	444,600
Total Installation Costs	$ 2,861,300
TOTAL DIRECT COSTS (Equipment + Installation)	$ 7,355,800
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 735,600
Construction and field expense (10% of direct costs)	735,600
Construction fees (10% of direct costs)	735,600
Startup (2% of direct costs)	147,100
Performance tests (minimum $2000)	10,000
TOTAL INDIRECT COSTS	$ 2,363,900
Contingencies (20% of direct and indirect costs)	$ 1,943,900
Total turnkey costs (Direct + Indirect + Contingencies)	$11,663,600
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 536,800
GRAND TOTAL (Turnkey + Land + Working Capital)	$12,202,400

[a] Quote from Babcock & Wilcox, Inc., August 17, 1978.

N.A. - Not applicable.

TABLE G-26. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED COAL-FIRED BOILER FIRING EASTERN HIGH-SULFUR COAL WITH A THERMAL INPUT OF 58.6 MW

(200 x 10^6 Btu/h; 750 psig/750°F design)

DIRECT COST	
Direct labor	$ 421,100
Supervision	136,900
Maintenance labor	192,200
Maintenance materials	a
Replacement parts	292,500
Electricity	278,300
Steam	N.A.
Cooling water	N.A.
Process water	3,000
Fuel	777,900
Bottom ash disposal	37,800
Chemicals	7,500
Total direct cost	$2,147,300
OVERHEAD	
Payroll (30% of direct labor)	$ 126,400
Plant (26% of labor, parts & maint.)	271,100
Total overhead costs	$ 397,500
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 466,500
Capital recovery factor (10.14% of total turnkey costs)	1,182,700
Interest on working capital (10% of working capital)	53,700
Total capital charges	$1,702,900
TOTAL ANNUALIZED COSTS	$4,247,700

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-27. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING EASTERN LOW-SULFUR COAL WITH A THERMAL INPUT OF 58.6 MW (200×10^6 Btu/h; 750 psig/750°F design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]	
Boiler (with fans and ducts)	$ 2,130,000
Stack	365,000
Instrumentation	228,000
Pulverizers	524,500
Feeders	110,000
Crushers	Incl. w/coal handling
Deaerator	29,000
Heaters	Incl. w/boiler
Boiler feed pumps	58,000
Condensate systems	16,300
Water treating system	20,000
Chemical feed	1,500
Compressed air system	20,000
Coal handling system	263,900
Ash disposal system	180,000
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.
Total Equipment Cost	$ 3,946,200
INSTALLATION COSTS, DIRECT	
Boiler (including foundations and steel)	$ 1,085,000
Stack	60,000
Instrumentation	35,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/boiler
Crushers	Incl. w/coal handling
Deaerator	5,000
Heaters	Incl. w/boiler
Boiler feed pumps	8,000
Condensate system	2,000
Water treating system	3,500
Chemical feed	1,500
Coal handling system	275,000 (incl. site prep.)
Ash disposal system	120,000
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.

(continued)

TABLE G-27 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	180,000
Duct work (not incl. w/boiler)	N.A.
Piping	80,000
Insulation	80,000
Painting	10,000
Electrical	160,000
Buildings	380,000
Total Installation Costs	$ 2,485,000
TOTAL DIRECT COSTS (Equipment + Installation)	$ 6,431,200
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 643,100
Construction and field expense (10% of direct costs)	643,100
Construction fees (10% of direct costs)	643,100
Startup (2% of direct costs)	128,600
Performance tests (minimum $2000)	10,000
TOTAL INDIRECT COSTS	$ 2,067,900
Contingencies (20% of direct and indirect costs)	$ 1,699,800
Total turnkey costs (Direct + Indirect + Contingencies)	$10,198,900
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 622,300
GRAND TOTAL (Turnkey + Land + Working Capital)	$10,823,200

[a] Quote from Babcock & Wilcox, Inc., August 17, 1978.

N.A. - Not applicable.

TABLE G-28. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE PULVERIZED-COAL-FIRED BOILER FIRING EASTERN LOW-SULFUR COAL WITH A THERMAL INPUT OF 58.6 MW

(200×10^6 Btu/h; 750 psig/750°F design)

DIRECT COST	
Direct labor	$ 421,200
Supervision	136,900
Maintenance labor	192,200
Maintenance materials	a
Replacement parts	250,000
Electricity	237,900
Steam	N.A.
Cooling water	N.A.
Process water	3,000
Fuel	1,219,400
Bottom ash disposal	21,000
Chemicals	7,500
Total direct cost	$2,489,100
OVERHEAD	
Payroll (30% of direct labor)	$ 126,400
Plant (26% of labor, parts & maint.)	260,100
Total overhead costs	$ 386,500
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 408,000
Capital recovery factor (10.14% of total turnkey costs)	1,034,200
Interest on working capital (10% of working capital)	62,200
Total capital charges	$1,504,400
TOTAL ANNUALIZED COSTS	$4,380,000

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-29. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING SUBBITUMINOUS COAL WITH A THERMAL INPUT OF 58.6 MW
(200 x 10^6 Btu/h; 750 psig/750° F design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST [a]

Boiler (with fans and ducts)	$ 3,067,200
Stack	365,000
Instrumentation	228,000
Pulverizers	754,600
Feeders	158,400
Crushers	Incl. w/coal handling
Deaerator	29,000
Heaters	Incl. w/boiler
Boiler feed pumps	58,000
Condensate systems	16,300
Water treating system	20,000
Chemical feed	1,500
Compressed air system	28,800
Coal handling system	380,000
Ash disposal system	259,200
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.
Total Equipment Cost	$ 5,366,000

INSTALLATION COSTS, DIRECT

Boiler (including foundations and steel)	$ 1,560,000
Stack	60,000
Instrumentation	35,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/boiler
Crushers	Incl. w/coal handling
Deaerator	5,000
Heaters	Incl. w/boiler
Boiler feed pumps	8,000
Condensate system	2,000
Water treating system	3,500
Chemical feed	1,500
Coal handling system	396,000
Ash disposal system	172,800
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.

(continued)

TABLE G-29 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	259,200
Duct work (not incl. w/boiler)	N.A.
Piping	115,200
Insulation	115,200
Painting	14,400
Electrical	160,000
Buildings	547,200
Total Installation Costs	$ 3,455,000
TOTAL DIRECT COSTS (Equipment + Installation)	$ 8,821,000
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 882,100
Construction and field expense (10% of direct costs)	882,100
Construction fees (10% of direct costs)	882,100
Startup (2% of direct costs)	176,400
Performance tests (minimum $2000)	10,000
TOTAL INDIRECT COSTS	$ 2,832,700
Contingencies (20% of direct and indirect costs)	$ 2,330,700
Total turnkey costs (Direct + Indirect + Contingencies)	$ 13,984,400
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 482,000
GRAND TOTAL (Turnkey + Land + Working Capital)	$ 14,468,400

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[a] Quote from Babcock & Wilcox, Inc., August 17, 1978.

N.A. - Not applicable.

TABLE G-30. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING SUBBITUMINOUS COAL WITH A THERMAL INPUT OF 58.6 MW (200 x 10^6 Btu/h; 750 psig/750°F design)

DIRECT COST	
Direct labor	$ 421,200
Supervision	136,900
Maintenance labor	192,200
Maintenance materials	a
Replacement parts	360,000
Electricity	342,500
Steam	N.A.
Cooling water	N.A.
Process water	3,000
Fuel	441,500
Bottom ash disposal	23,100
Chemicals	7,500
Total direct cost	$1,927,900
OVERHEAD	
Payroll (30% of direct labor)	$ 126,400
Plant (26% of labor, parts & maint.)	288,700
Total overhead costs	$ 415,100
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 559,400
Capital recovery factor (10.14% of total turnkey costs)	1,418,000
Interest on working capital (10% of working capital)	48,200
Total capital charges	$2,025,600
TOTAL ANNUALIZED COSTS	$4,368,600

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-31. ESTIMATED CAPITAL COSTS OF A PACKAGE WATER-TUBE BOILER FIRING RESIDUAL OIL WITH A THERMAL INPUT OF 8.8 MW (30×10^6 Btu/h; 150 psig/sat. temp. design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST [a]

Boiler (with fans & ducts)	$ 150,000
Stack	5,000
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deaerator	7,000
Heaters	N.A.
Boiler feed pumps	13,500
Condensate systems	3,500
Water treating system	8,000
Chemical feed	1,500
Compressed air system	N.A.
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	33,000
Total Equipment Cost	$ 221,500

INSTALLATION COST, DIRECT

Boiler (including foundations and steel)	$ 10,000
Stack	3,000
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deaerator	2,500
Heaters	N.A.
Boiler feed pumps	3,000
Condensate system	1,000
Water treating system	2,000
Chemical feed	1,500
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	8,000

(continued)

TABLE G-31 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	15,000
Duct work (not incl. w/boiler)	N.A.
Piping	26,000
Insulation	20,000
Painting	4,000
Electrical	21,000
Buildings	70,000
Total installation cost	$ 187,000
TOTAL DIRECT COSTS (equipment + installation)	$ 408,500
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 40,800
Construction and field expense (10% of direct costs)	40,800
Construction fees (10% of direct costs)	40,800
Startup (2% of direct costs)	8,200
Performance tests (minimum $2000)	2,000
TOTAL INDIRECT COSTS	$ 132,600
Contingencies (20% of direct and indirect costs)	$ 108,200
Total Turnkey Costs (direct+indirect+contingencies)	$ 649,300
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 146,500
GRAND TOTAL (turnkey+land+working capital)	$ 797,800

[a] Quote from Zurn Industries, Inc., May 25, 1978.

N.A. - Not applicable.

TABLE G-32. ESTIMATED ANNUALIZED COSTS OF A PACKAGE WATER-TUBE BOILER FIRING RESIDUAL OIL WITH A THERMAL INPUT OF 8.8 MW OF 8.8 MW (30 x 10^6 Btu/h; 150 psig/sat. temp. design)

DIRECT COST	
Direct labor	$ 105,300
Supervision	68,500
Maintenance labor	32,000
Maintenance materials	a
Replacement parts	30,000
Electricity	29,300
Steam	N.A.
Cooling water	N.A.
Process water	400
Fuel	319,400
Bottom ash disposal	N.A.
Chemicals	1,000
Total direct cost	$ 585,900
OVERHEAD	
Payroll (30% of direct labor)	$ 31,600
Plant (26% of labor, parts & maint.)	61,300
Total overhead costs	$ 92,900
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 26,000
Capital recovery factor (10.61% of total turnkey costs)	68,900
Interest on working capital (10% of working capital)	14,700
Total capital charges	$ 109,600
TOTAL ANNUALIZED COSTS	$ 788,400

[a] Included with replacement parts.

N.A. - Not applicable.

TABLE G-33. ESTIMATED CAPITAL COSTS OF A PACKAGE WATER-TUBE BOILER FIRING DISTILLATE OIL WITH A THERMAL INPUT OF 44 MW (150 x 10^6 Btu/h; 750 psig/750°F design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST [a]

Boiler (with fans & ducts)	$ 600,000
Stack	14,500
Instrumentation	Incl. w/boiler
Pulverizers	N. A.
Feeders	N. A.
Crushers	N. A.
Deaerator	21,600
Heaters	N.A.
Boiler feed pumps	53,600
Condensate systems	6,700
Water treating system	18,000
Chemical feed	1,500
Compressed air system	N.A.
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	39,000
Total Equipment Cost	$ 754,900

INSTALLATION COST, DIRECT

Boiler (including foundations and steel)	$ 20,000
Stack	6,500
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deaerator	4,000
Heaters	N.A.
Boiler feed pumps	7,500
Condensate system	1,500
Water treating system	3,000
Chemical feed	1,500
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	15,000

(continued)

TABLE G-33 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	30,000
Duct work (not incl. w/boiler)	N.A.
Piping	65,000
Insulation	30,000
Painting	5,000
Electrical	40,000
Buildings	100,000
Total installation cost	$ 329,000
TOTAL DIRECT COSTS (equipment + installation)	$ 1,083,900
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 108,400
Construction and field expense (10% of direct costs)	108,400
Construction fees (10% of direct costs)	108,400
Startup (2% of direct costs)	21,700
Performance tests (minimum $2000)	3,500
TOTAL INDIRECT COSTS	$ 350,400
Contingencies (20% of direct and indirect costs)	$ 286,900
Total Turnkey Costs (direct+indirect+contingencies)	$ 1,721,200
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 656,500
GRAND TOTAL (turnkey+land+working capital)	$ 2,379,700

[a] Quote from Zurn Industries, Inc., May 25, 1978.

N.A. - Not applicable.

TABLE G-34. ESTIMATED ANNUALIZED COSTS OF A PACKAGE, WATER-TUBE BOILER FIRING DISTILLATE OIL WITH A THERMAL INPUT OF 44 MW. (150 x 10^6 Btu/h; 750 psig/750°F design)

DIRECT COST	
Direct labor	$ 210,600
Supervision	68,500
Maintenance labor	64,100
Maintenance materials	a.
Replacement parts	60,000
Electricity	47,100
Steam	N.A.
Cooling water	N.A.
Process water	2,000
Fuel	2,168,100
	N.A.
Chemicals	5,500
Total direct cost	$ 2,625,900
OVERHEAD	
Payroll (30% of direct labor)	$ 63,200
Plant (26% of labor, parts & maint.)	104,800
Total overhead costs	$ 168,000
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 68,800
Capital recovery factor (10.6% of total turnkey costs)	182,600
Interest on working capital (10% of working capital)	65,700
Total capital charges	$ 317,100
TOTAL ANNUALIZED COSTS	$ 3,111,000

[a] Included with replacement parts.
N.A. - Not applicable.

TABLE G-35. ESTIMATED CAPITAL COSTS OF A PACKAGE, WATER-TUBE BOILER FIRING NATURAL GAS WITH A THERMAL INPUT OF 44 MW (150×10^6 Btu/h; 750 psig/750°F design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]

Boiler (with fans & ducts)	$ 600,000
Stack	14,500
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deaerator	21,600
Heaters	N.A.
Boiler feed pumps	53,600
Condensate systems	6,700
Water treating system	18,000
Chemical feed	1,500
Compressed air system	N.A.
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	N.A.
Total Equipment Cost	$ 715,900

INSTALLATION COST, DIRECT

Boiler (including foundations and steel)	$ 20,000
Stack	6,500
Instrumentation	Incl. w/boiler
Pulverizers	N.A.
Feeders	N.A.
Crushers	N.A.
Deaerator	4,000
Heaters	N.A.
Boiler feed pumps	7,500
Condensate system	1,500
Water treating system	3,000
Chemical feed	1,500
Coal handling system	N.A.
Ash disposal system	N.A.
Thawing equipment	N.A.
Fuel-oil system	N.A.

(continued)

TABLE G-35 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	30,000
Duct work (not incl. w/boiler)	N.A.
Piping	74,000
Insulation	30,000
Painting	5,000
Electrical	40,000
Buildings	100,000
Total installation cost	$ 323,000
TOTAL DIRECT COSTS (equipment + installation)	$1,038,900
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 103,900
Construction and field expense (10% of direct costs)	103,900
Construction fees (10% of direct costs)	103,900
Startup (2% of direct costs)	20,800
Performance tests (minimum $2000)	3,500
TOTAL INDIRECT COSTS	$ 336,000
Contingencies (20% of direct and indirect costs)	$ 275,000
Total Turnkey Costs (direct+indirect+contingencies)	$1,649,900
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 466,800
GRAND TOTAL (turnkey+land+working capital)	$2,118,700

[a] Quote from Cleaver-Brooks, May 11, 1978.

N.A. - Not applicable.

TABLE G-36. ESTIMATED ANNUALIZED COSTS OF A PACKAGE, WATER-TUBE BOILER FIRING NATURAL GAS WITH A THERMAL INPUT OF 44 MW (150×10^6 Btu/h; 750 psig/750°F)

DIRECT COST	
Direct labor	$ 210,600
Supervision	68,500
Maintenance labor	64,100
Maintenance materials	a.
Replacement parts	60,000
Electricity	47,100
Steam	N.A.
Cooling water	N.A.
Process water	2,000
Fuel	1,409,300
	N.A.
Chemicals	5,500
Total direct cost	$ 1,867,100
OVERHEAD	
Payroll (30% of direct labor)	$ 63,200
Plant (26% of labor, parts & maint.)	104,800
Total overhead costs	$ 168,000
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 66,000
Capital recovery factor (10.61% of total turnkey costs)	175,100
Interest on working capital (10% of working capital)	46,700
Total capital charges	$ 287,800
TOTAL ANNUALIZED COSTS	$ 2,322,900

[a] Included with replacement parts.
N. A. - Not applicable.

TABLE G-37. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, CHAIN-GRATE-STOKER BOILER FIRING EASTERN MEDIUM-SULFUR COAL WITH A THERMAL INPUT OF 22 MW (75×10^6 Btu/h; 150 psig/sat. temp. design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]

Boiler (with fans & ducts)	$ 673,400
Stack	80,000
Instrumentation	50,000
Pulverizers	150,000
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	15,900
Heaters	N.A.
Boiler feed pumps	25,300
Condensate systems	8,700
Water treating system	15,000
Chemical feed	1,400
Compressed air system	N.A.
Coal handling system	146,500
Ash disposal system	120,000
Thawing equipment	N.A.
Fuel-oil system	N.A.
Total Equipment Cost	$1,286,600

INSTALLATION COST, DIRECT

Boiler (including foundations and steel)	$ 435,100
Stack	20,000
Instrumentation	15,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/coal handling
Crushers	Incl. w/coal handling
Deaerator	3,500
Heaters	N.A.
Boiler feed pumps	5,500
Condensate system	1,300
Water treating system	2,500
Chemical feed	1,500
Coal handling system	155,400
Ash disposal system	62,200
Thawing equipment	N.A.
Fuel-oil system	N.A.

(continued)

TABLE G-37 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	82,900
Duct work (not incl. w/boiler)	N.A.
Piping	51,800
Insulation	41,400
Painting	7,300
Electrical	75,000
Buildings	207,200
Total installation cost	$1,167,600
TOTAL DIRECT COSTS (equipment + installation)	$2,454,200
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 245,400
Construction and field expense (10% of direct costs)	245,400
Construction fees (10% of direct costs)	245,400
Startup (2% of direct costs)	49,100
Performance tests (minimum $2000)	7,000
TOTAL INDIRECT COSTS	$ 792,300
Contingencies (20% of direct and indirect costs)	$ 649,300
Total Turnkey Costs (direct+indirect+contingencies)	$3,895,800
Land	$ 2,000
Working capital (25% of total direct operating costs)	$ 267,500
GRAND TOTAL (turnkey+land+working capital)	$4,165,300

[a] Quote from Zurn Industries, Inc., May 25, 1978.

N.A. - Not applicable.

TABLE G-38. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE, CHAIN-GRATE-STOKER BOILER FIRING EASTERN MEDIUM-SULFUR COAL WITH A THERMAL INPUT OF 22 MW (75 x 10^6 Btu/h; 150 psig/sat. temp. design)

DIRECT COST	
Direct labor	$ 210,600
Supervision	136,900
Maintenance labor	128,200
Maintenance materials	a.
Replacement parts	103,600
Electricity	51,400
Steam	N.A.
Cooling water	N.A.
Process water	1,100
Fuel	374,500
Bottom ash disposal	58,900
Chemicals	4,900
Total direct cost	$ 1,070,100
OVERHEAD	
Payroll (30% of direct labor)	$ 63,200
Plant (26% of labor, parts & maint.)	150,000
Total overhead costs	$ 213,800
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 155,800
Capital recovery factor (10.14% of total turnkey costs)	395,000
Interest on working capital (10% of working capital)	26,800
Total capital charges	$ 577,600
TOTAL ANNUALIZED COSTS	$ 1,861,500

[a] Included with replacement parts.

N. A. - Not applicable.

TABLE G-39. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING EASTERN MEDIUM-SULFUR COAL WITH A THERMAL INPUT OF 117.2 MW (400×10^6 Btu/hr; 750 psig/750°F design)

CAPITAL COSTS

DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]	
Boiler (with fans & ducts)	$ 3,571,300
Stack	650,000
Instrumentation	378,600
Pulverizers	877,000
Feeders	186,800
Crushers	Incl. w/coal handling
Deaerator	60,000
Heaters	Incl. w/boiler
Boiler feed pumps	150,000
Condensate systems	25,000
Water treating system	60,000
Chemical feed	4,000
Compressed air system	41,800
Coal handling system	1,044,000
Ash disposal system	344,500
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.
Total Equipment Cost	$ 7,393,000
INSTALLATION COST, DIRECT	
Boiler (including foundations and steel)	$ 2,265,500
Stack	Incl. w/equipment
Instrumentation	110,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/boiler
Crushers	Incl. w/coal handling
Deaerator	12,000
Heaters	Incl. w/boiler
Boiler feed pumps	18,000
Condensate system	10,000
Water treating system	16,000
Chemical feed	2,000
Coal handling system	657,700
Ash disposal system	271,400
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.

(continued)

TABLE G-39 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	344,500
Duct work (not incl. w/boiler)	N.A.
Piping	130,500
Insulation	114,800
Painting	16,700
Electrical	340,000
Buildings	678,600
Total installation cost	$ 4,987,700
TOTAL DIRECT COSTS (equipment + installation)	$ 12,380,700
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 1,238,100
Construction and field expense (10% of direct costs)	1,238,100
Construction fees (10% of direct costs)	1,238,100
Startup (2% of direct costs)	247,600
Performance tests (minimum $2000)	15,000
TOTAL INDIRECT COSTS	$ 3,976,900
Contingencies (20% of direct and indirect costs)	$ 3,271,500
Total Turnkey Costs (direct+indirect+contingencies)	$ 19,629,100
Land	$ 4,000
Working capital (25% of total direct operating costs)	$ 1,074,200
GRAND TOTAL (turnkey+land+working capital)	$ 20,707,300

[a] Quote from Babcock & Wilcox, Inc., August 19, 1978.

N.A. - Not applicable.

TABLE G-40. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING EASTERN MEDIUM-SULFUR COAL WITH A THERMAL INPUT OF 117.2 MW (400×10^6 Btu/hr; 750 psig/750°F design)

DIRECT COST	
Direct labor	$ 737,100
Supervision	205,400
Maintenance labor	384,500
Maintenance materials	a
Replacement parts	365,400
Electricity	501,100
Steam	N.A.
Cooling water	N.A.
Process water	6,100
Fuel	1,997,000
Bottom ash disposal	84,000
Chemicals	16,000
Total direct cost	$ 4,296,600
OVERHEAD	
Payroll (30% of direct labor)	$ 221,100
Plant (26% of labor, parts & maint.)	440,000
Total overhead costs	$ 661,100
BYRRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 785,200
Capital recovery factor (10.14% of total turnkey costs)	1,990,400
Interest on working capital (10% of working capital)	107,400
Total capital charges	$ 2,883,000
TOTAL ANNUALIZED COSTS	$ 7,840,700

[a] Included with replacement parts.
N.A. - Not applicable.

TABLE G-41. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING EASTERN HIGH-SULFUR COAL WITH A THERMAL INPUT OF 117.2 MW (400 x 10^6 Btu/hr; 750 psig/750°F design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]

Boiler (with fans & ducts)	$ 4,002,300
Stack	650,000
Instrumentation	378,600
Pulverizers	982,800
Feeders	209,300
Crushers	Incl. w/coal handling
Deaerator	60,000
Heaters	Incl. w/boiler
Boiler feed pumps	150,000
Condensate systems	25,000
Water treating system	60,000
Chemical feed	4,000
Compressed air system	46,800
Coal handling system	1,170,000
Ash disposal system	386,100
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.
Total Equipment Cost	$ 8,124,900

INSTALLATION COST, DIRECT

Boiler (including foundations and steel)	$ 2,538,900
Stack	Incl. w/equipment
Instrumentation	110,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/boiler
Crushers	Incl. w/coal handling
Deaerator	12,000
Heaters	Incl. w/boiler
Boiler feed pumps	18,000
Condensate system	10,000
Water treating system	16,000
Chemical feed	2,000
Coal handling system	737,100
Ash disposal system	304,200
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.

(continued)

TABLE G-41 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	386,000
Duct work (not incl. w/boiler)	N.A.
Piping	146,000
Insulation	129,000
Painting	19,000
Electrical	340,000
Buildings	761,000
Total installation cost	$ 5,529,200
TOTAL DIRECT COSTS (equipment + installation)	$ 13,654,100
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 1,365,400
Construction and field expense (10% of direct costs)	1,365,400
Construction fees (10% of direct costs)	1,365,400
Startup (2% of direct costs)	273,100
Performance tests (minimum $2000)	15,000
TOTAL INDIRECT COSTS	$ 4,384,300
Contingencies (20% of direct and indirect costs)	$ 3,607,700
Total Turnkey Costs (direct+indirect+contingencies)	$ 21,646,100
Land	$ 4,000
Working capital (25% of total direct operating costs)	$ 987,900
GRAND TOTAL (turnkey+land+working capital)	$ 22,638,000

[a] Quote from Babcock & Wilcox, Inc., August 19, 1978.

N.A. - Not applicable.

TABLE G-42. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING EASTERN HIGH-SULFUR COAL WITH A THERMAL INPUT OF 117.2 MW (400×10^6 Btu/hr; 750 psig/750°F design)

DIRECT COST	
Direct labor	$ 737,100
Supervision	205,400
Maintenance labor	384,500
Maintenance materials	a
Replacement parts	409,500
Electricity	561,600
Steam	N.A.
Cooling water	N.A.
Process water	6,100
Fuel	1,555,800
Bottom ash disposal	75,500
Chemicals	16,000
Total direct cost	$ 3,951,500
OVERHEAD	
Payroll (30% of direct labor)	$ 221,100
Plant (26% of labor, parts & maint.)	451,500
Total overhead costs	$ 672,600
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 865,800
Capital recovery factor (10.14% of total turnkey costs)	2,194,900
Interest on working capital (10% of working capital)	98,800
Total capital charges	$ 3,159,500
TOTAL ANNUALIZED COSTS	$ 7,783,600

[a] Included in replacement parts.

N.A. - Not Applicable

TABLE G-43. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING EASTERN LOW-SULFUR COAL WITH A THERMAL INPUT OF 117.2 MW (400×10^6 Btu/hr; 750 psig/750°F design)

CAPITAL COSTS

DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]

Boiler (with fans & ducts)	$ 3,420,800
Stack	650,000
Instrumentation	378,600
Pulverizers	840,000
Feeders	178,900
Crushers	Incl. w/coal handling
Deaerator	60,000
Heaters	Incl. w/boiler
Boiler feed pumps	150,000
Condensate systems	25,000
Water treating system	60,000
Chemical feed	4,000
Compressed air system	40,000
Coal handling system	1,000,000
Ash disposal system	330,000
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.
Total Equipment Cost	$ 7,137,300

INSTALLATION COST, DIRECT

Boiler (including foundations and steel)	$ 2,170,000
Stack	Incl. w/equipment
Instrumentation	110,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/boiler
Crushers	Incl. w/coal handling
Deaerator	12,000
Heaters	Incl. w/boiler
Boiler feed pumps	18,000
Condensate system	10,000
Water treating system	16,000
Chemical feed	2,000
Coal handling system	630,000
Ash disposal system	260,000
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.

(continued)

TABLE G-43 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	$ 330,000
Duct work (not incl. w/boiler)	N.A.
Piping	125,000
Insulation	110,000
Painting	16,000
Electrical	340,000
Buildings	650,000
Total installation cost	$ 4,799,000
TOTAL DIRECT COSTS (equipment + installation)	$11,936,300
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 1,193,600
Construction and field expense (10% of direct costs)	1,193,600
Construction fees (10% of direct costs)	1,193,600
Startup (2% of direct costs)	238,700
Performance tests (minimum $2000)	15,000
TOTAL INDIRECT COSTS	$ 3,834,500
Contingencies (20% of direct and indirect costs)	$ 3,154,200
Total Turnkey Costs (direct+indirect+contingencies)	$18,925,000
Land	$ 4,000
Working capital (25% of total direct operating costs)	$ 1,165,000
GRAND TOTAL (turnkey+land+working capital)	$20,094,000

[a] Quote from Babcock & Wilcox, Inc., August 19, 1978.

N.A. - Not applicable.

TABLE G-44. ESTIMATED ANNUALIZED COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING EASTERN LOW-SULFUR COAL WITH A THERMAL INPUT OF 117.2 MW (400×10^6 Btu/hr; 750 psig/750°F design)

DIRECT COST	
Direct labor	$ 737,100
Supervision	205,400
Maintenance labor	384,500
Maintenance materials	[a]
Replacement parts	350,000
Electricity	480,000
Steam	N.A.
Cooling water	N.A.
Process water	6,100
Fuel	2,438,800
Bottom ash disposal	42,000
Chemicals	16,000
Total direct cost	$ 4,659,900
OVERHEAD	
Payroll (30% of direct labor)	$ 221,100
Plant (26% of labor, parts & maint.)	436,000
Total overhead costs	$ 657,100
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 757,000
Capital recovery factor (10.14% of total turnkey costs)	1,919,000
Interest on working capital (10% of working capital)	116,500
Total capital charges	$ 2,792,500
TOTAL ANNUALIZED COSTS	$ 8,109,500

[a] Included with replacement parts.

N.A. - Not Applicable

TABLE G-45. ESTIMATED CAPITAL COSTS OF A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING SUBBITUMINOUS COAL WITH A THERMAL INPUT OF 117.2 MW (400×10^6 Btu/hr; 750 psig/750°F design)

CAPITAL COSTS
DATE OF ESTIMATE June 30, 1978 (FOR COSTS INDEXING)

EQUIPMENT COST[a]

Boiler (with fans & ducts)	$ 4,926,000
Stack	650,000
Instrumentation	378,600
Pulverizers	1,209,600
Feeders	257,600
Crushers	Incl. w/coal handling
Deaerator	60,000
Heaters	Incl. w/boiler
Boiler feed pumps	150,000
Condensate systems	25,000
Water treating system	60,000
Chemical feed	4,000
Compressed air system	57,600
Coal handling system	1,440,000
Ash disposal system	475,200
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.
Total Equipment Cost	$ 9,693,600

INSTALLATION COST, DIRECT

Boiler (including foundations and steel)	$ 3,124,800
Stack	Incl. w/equipment
Instrumentation	110,000
Pulverizers	Incl. w/boiler
Feeders	Incl. w/boiler
Crushers	Incl. w/coal handling
Deaerator	12,000
Heaters	Incl. w/boiler
Boiler feed pumps	18,000
Condensate system	10,000
Water treating system	16,000
Chemical feed	2,000
Coal handling system	907,200
Ash disposal system	374,400
Thawing equipment	Incl. w/coal handling
Fuel-oil system	N.A.

(continued)

TABLE G-45 (continued)

INSTALLATION COSTS, DIRECT (cont.)	
Foundations and supports	475,000
Duct work (not incl. w/boiler)	N.A.
Piping	180,000
Insulation	158,000
Painting	23,000
Electrical	340,000
Buildings	936,000
Total installation cost	$ 6,686,400
TOTAL DIRECT COSTS (equipment + installation)	$16,380,000
INSTALLATION COSTS, INDIRECT	
Engineering (10% of direct costs)	$ 1,638,000
Construction and field expense (10% of direct costs)	1,638,000
Construction fees (10% of direct costs)	1,638,000
Startup (2% of direct costs)	327,600
Performance tests (minimum $2000)	15,000
TOTAL INDIRECT COSTS	$ 5,256,600
Contingencies (20% of direct and indirect costs)	$ 4,327,300
Total Turnkey Costs (direct+indirect+contingencies)	$ 25,963,900
Land	$ 4,000
Working capital (25% of total direct operating costs)	$ 868,700
GRAND TOTAL (turnkey+land+working capital)	$ 26,836,600

[a] Quote from Babcock & Wilcox, Inc., August 19, 1978.

N.A. - Not applicable.

TABLE G-46. ESTIMATED ANNUALIZED COSTS FOR A FIELD-ERECTED, WATER-TUBE, PULVERIZED-COAL-FIRED BOILER FIRING SUBBITUMINOUS COAL WITH A THERMAL INPUT OF 117.2 MW (400 x 10^6 Btu/hr; 750 psig/750°F design)

DIRECT COST	
Direct labor	$ 737,100
Supervision	205,400
Maintenance labor	384,500
Maintenance materials	a
Replacement parts	504,000
Electricity	691,200
Steam	N.A.
Cooling water	N.A.
Process water	6,100
Fuel	883,000
Bottom ash disposal	47,300
Chemicals	16,000
Total direct cost	$ 3,474,600
OVERHEAD	
Payroll (30% of direct labor)	$ 221,100
Plant (26% of labor, parts & maint.)	476,100
Total overhead costs	$ 697,200
BYPRODUCT CREDITS	N.A.
CAPITAL CHARGES	
G & A, taxes & insurance (4% of total turnkey costs)	$ 1,038,600
Capital recovery factor (10.14% of total turnkey costs)	2,632,700
Interest on working capital (10% of working capital)	86,900
Total capital charges	$ 3,758,200
TOTAL ANNUALIZED COSTS	$ 7,930,000

[a] Included in replacement parts.

N.A. - Not Applicable